BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

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| ---------In the Matter of-------- <br> <br> PUBLIC UTILITIES COMMISSION <br> <br> Instituting a Proceeding to Investigate the Implementation of Feed-in Tariffs. | ) <br> ) <br> ) <br> ) <br> ) <br> ) <br> ) <br> ) | DOCKET NO. 2008-0273 |

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PUBLIC UTILITIES COMMISSION

**THE DEPARTMENT OF BUSINESS, ECONOMIC DEVELOPMENT, AND TOURISM'S OPENING BRIEF**

**AND**

**CERTIFICATE OF SERVICE**

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**THE DEPARTMENT OF BUSINESS, ECONOMIC DEVELOPMENT, AND TOURISM'S OPENING BRIEF**

The Department of Business, Economic Development, and Tourism ("DBEDT"), by and through its Director ("Director") in his capacity as the Energy Resources Coordinator ("ERC"), through the undersigned Deputy Attorney General, hereby submits to the Hawaii Public Utilities Commission ("Commission" or "PUC") its Opening Brief in the instant docket, an investigatory proceeding on the implementation of feed-in tariffs.

## Background

On October 24, 2008, the PUC initiated the instant docket, Docket No. 2008-0273, to examine the issues related to the implementation of feed-in tariffs in the service territories served by Hawaiian Electric Company ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Limited ("MECO") (collectively the "HECO Companies"). The PUC designated the HECO Companies and the Consumer Advocate ("CA") as parties to the docket as they were signatories to the Energy Agreement ("Agreement") entered into between the State and the HECO Companies on October 20, 2008, which was cited as the basis for the PUC's initiation of this docket. On November 28, 2008, the PUC issued its Order granting intervenor status to eighteen (18) parties including DBEDT[1].

On December 11, 2008, the PUC issued a Scoping Paper titled "Feed-in Tariffs: Best Design Focusing Hawaii's Investigation" prepared by the National Regulatory Research Institute (NRRI). The PUC Scoping Paper identified several legal and non-legal issues relating to feed-in tariffs which the Parties were required to respond to by January 12, 2009 and January 26, 2009, respectively. On December 23, 2008, the HECO Companies and the CA filed their joint proposal on feed-in tariffs design ("HECO/CA Joint FiTs Proposal") pursuant to the PUC's Order initiating the investigation.

On January 20, 2009, the PUC issued its Order setting forth the issues, procedures, and schedule to govern the proceeding,

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[1] The intervenors in the docket include DBEDT; City and County of Honolulu; the County of Hawaii; Sempra Generation; Hawaii Holdings LLC, doing business as First Wind Hawaii (First Wind); Haiku Design and Analysis (HDA); Hawaii Renewable Energy Alliance (HREA); SOPOGY Inc.; Life of the Land (LOL); Alexander & Baldwin Inc. through its division, Hawaiian Commercial & Sugar Company (HC&S); Clean Energy Maui LLC; Tawhiri Power LLC; Hawaii Bioenergy LLC (HBE); Maui Land & Pineapple Company, Inc. (MLP); Hawaii Solar Energy Association (HSEA); The Solar Alliance; and Zero Emissions Leasing LLC.

adopting and modifying sections from the proposed stipulated procedural orders[2] filed by the Parties. The issues to be addressed in the docket as set forth in the PUC's Order include the following:

A. Purpose of project-based feed-in tariffs (PBFiTs):

1) What, if any, purpose do PBFiTs play in meeting Hawaii's clean energy and energy independence goals, given Hawaii's existing renewable energy purchase requirements by utilities?

2) What are the potential benefits and adverse consequences of PBFiTs for the utilities, to ratepayers and the State of Hawaii;

3) Why is or is not the PBFiT the superior method to meet Hawaii's clean energy and energy independence goals?

B. Legal Issues:

4) What, if any, modifications are prudent or necessary to existing federal or state laws, rules, regulations or other requirements to remove any barriers or to facilitate the implementation of a feed-in tariff not based on avoided costs?

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[2] On December 22, 2008, a proposed Stipulated Procedural Order (SPO) was submitted by the HECO Companies, CA, DBEDT, City & County of Honolulu, County of Hawaii, Sempra Generation, and First Wind. HDA also filed its own proposed SPO, and HREA, SOPOGY, LOL, HC&S, Clean Energy Maui and Tawhiri Power filed joinders to HDA's SPO.

5) What evidence must the Commission consider in establishing a feed-in tariff and has that evidence been presented in this investigation?

C. Role of Other Methodologies:

6) What role do other methodologies play in the utility's procurement of renewable energy with and without a PBFiT, including but not limited to power purchase contracts, competitive bidding, avoided cost offerings and net energy metering?

D. Best design for a PBFiT or alternative method:

7) What is the best design, including the cost basis, for PBFiTs or other alternative feed-in tariffs in order to accelerate and increase the development of Hawaii's renewable energy resources and their integration into the utility system?

E. Eligibility Requirements:

8) What renewable energy projects should be eligible for which renewable electricity purchase methods or individual tariffs and when?

F. Analysis of the cost to consumers and appropriateness of caps:

9) What is the cost to consumers and others of the proposed feed-in tariffs?

10) Should the Commission impose caps on the total amount purchased through any mechanism or tariff based upon these financial effects, technical limitations or other reasons?

G. Procedural Issues:

11) What process should the Commission implement for evaluating, determining and updating renewable energy purchased power mechanisms or tariffs?

12) What are the administrative impacts of the proposed approach to the Commission and the parties?

Pursuant to the PUC-approved procedural schedule, the Parties submitted their opening and final Statements of Position on the above issues on February 25, 2009, and March 30, 2009, respectively. On April 1, 2009, the Commission issued its Order Establishing Hearing Procedures for the panel hearings scheduled for April 13-17, 2009 pursuant to the procedural schedule. As set forth in the Order Establishing Hearing Procedures, the Commission would decide in this proceeding: (a) whether feed-in tariffs for renewable energy are desirable; and if so, (b) what rights and obligations those tariffs should establish. The purpose of the panel hearings is to assist the Commission in making these decisions.

Consistent with the purpose of the panel hearings, the Order Establishing Hearing Procedure established eight panels of witnesses representing eight subject areas, which while consistent, replaced the issues set forth in the Procedural Order issued by the Commission on January 20, 2009 to avoid confusion and to provide additional clarity. The eight subject areas addressed by the eight panels of witnesses, including the questions requiring Commission decisions under each subject area, included the following:

I. Given the four existing renewable producer options (Schedule Q, net metering, competitive bid, and non-bid PPAs), what contribution would FiTs make toward achieving Hawaii's renewable energy goals?

   1. Should the Commission state a quantitative goal for renewable purchases in Hawaii generally and for FiTs specifically?

   2. Are there gaps or sub-optimalities in present programs that make FiTs necessary to achieve Hawaii goals?

   3. Net Metering: Should net metering be continued, without change, in the presence of a FiT? If not, what renewables (technologies and sizes) should Net Energy Metering apply to and what renewables should FiT apply to?

4. Schedule Q: Should Schedule Q be continued, without change, in the presence of a FiT? If not, what renewables (technologies and sizes) should Schedule Q apply to and what renewables should FiT apply to?

5. Negotiated power purchase agreements: Should present practices be continued, without change, in the presence of a FiT? If not, what renewables (technologies and sizes) should present practices apply to and what renewables should FiT apply to?

6. Competitive bidding: Should present practices be continued, without change, in the presence of a FiT? If not, what renewables (technologies and sizes) should present practices apply to and what renewables should FiT apply to?

II. What are the physical limitations on the utility's ability to purchase renewables?

1. Concerning standards and procedures to ensure that FiT sales promote reliability: Should they be part of the tariffs, or should they exist outside the tariffs (e.g., in interconnection rules or in project-by project negotiations)?

III. What are the appropriate criteria for eligibility to sell under FiT tariffs?

1. What technologies should be eligible for the FiT?
2. What are the maximum and minimum capacities of projects that should be eligible for the FiT?
3. Should projects owned by utilities or their affiliates be eligible for the FiT and, if so, under what conditions?

IV. What decisions are necessary to ensure that FiTs rates are just and reasonable, as required by Hawaii law?

1. Should the FiT facilitate the cost recovery of only the most cost-effective projects, a typical project, or most projects?
2. What is a reasonable return on equity for a FiT project?
3. What cost and performance information is needed to calculate FiT rates?
4. What are appropriate methodologies for calculating FiT rates?
5. What interconnection costs should the FiT developer bear?
6. How should FiT participants be compensated for curtailment?

7. How should the FiT rates consider tax policies for renewables?
8. Should the FiT rate to which a project is otherwise entitled, be adjusted downward to reflect any rebates or other financial benefits received by the project?
9. Should the FiT automatically reflect changes in tax law and renewables programs or should such changes take place in periodic updates?
10. How should the FiT account for project reliability benefits or lack thereof?
11. Once a project receives a FiT rate, under what circumstances should its FiT rate change?
12. Should the FiT contain baseline rates for new technologies?
13. How should FiT rates account for inflation?
14. How could FiT rates comply with the "avoided cost" provision on HRS §269-27.2?

V. What non-rate terms are necessary to make FiTs just and reasonable?

1. What should be the term of the FiT?
2. Is there a need for a service contract along with the feed-in tariff, or should the tariff

itself contain all the necessary legal rights and obligations?

3. What should be the rights and obligations associated with project output on expiration of the FiT term?
4. What FiT attributes should be subject to periodic reexamination?
5. When should periodic reexaminations occur?
6. What data should FiT projects have to submit?
7. Who should receive renewable energy credits and green attributes?
8. Should the tariff state the possibility that the commission can suspend the FiT based on reliability concerns?

VI. Utility cost recovery: What principles should apply?

1. Are either additions to rate base or assured recovery for the utility appropriate?
2. How should FiT costs be allocated to the customers of the three HECO companies?

VII. What are the appropriate processes for accepting and interconnecting FiT projects?

1. What queuing and interconnection procedures should FiT projects use?

2. What, if any, modifications should be made to Rule 14 provisions for penetration of generating sources and remote control?

VIII. If the Commission does approve FiTs, what actions can it take to keep total costs reasonable?

1. Should the commission limit the FiT scope (i.e., eligible technologies, project size) initially? If so, at what rate should the commission then expand the scope?
2. Should the commission establish purchase caps as a means of keeping total costs reasonable? If so, what purchase caps should the FiT contain?
3. Should the FiT rates decline over time?
4. Should the tariff state the possibility that the commission can suspend the FiT based on cost concerns?

In addition to the issues and questions requiring Commission decisions, Exhibit A of the PUC Order Establishing Hearing Procedures also listed other more detailed questions under each major subject area, the answers to which will help the Commission make decisions in those areas, as well as to help the Parties prepare for the panel hearings.

During the panel hearing on April 16, 2009, NRRI issued a list of legal questions that the parties were asked by the Commission to address in the post hearing briefs scheduled for filing with the Commission on May 22, 2009. On May 7, 2009, the PUC counsel sent the parties via email a recap of the legal questions that were identified at the hearing for briefing, and included the following (renumbered only to provide internal consistency with the structure of this Opening Brief):

IX. General:

A. Does Section 269-27.2(b), HRS, empower the Commission to establish a set of feed-in tariffs that compel the utility to offer to purchase power from non-fossil producers at rates, terms and conditions established by the Commission, even if those rates, terms and conditions differ from those proposed by the utility in this proceeding?

B. Does the Commission have authority to mandate that the utility procure a particular quantity of non-fossil electricity, exceeding the statutory RPS requirements? Can the Commission establish deadlines? What statutes grant this authority?

C. Is the Energy Agreement legally binding on any one? In what way? Who could sue whom for noncompliance?

D. Does the Commission have authority to adopt FiTs in this proceeding without having completed a proceeding on Clean Energy Scenario Planning?

E. Under a FiT regime, will there be a need for a contract between seller and the utility buyer? What form would these written contracts take? What seller obligations should these contracts cover?

F. Assuming there are contracts associated with FiT sales, what is the Commission's statutory obligation to review these contracts? What are effective procedures to expedite Commission review?

X. Cost:

A. Does HRS §269-27.2 impose any limit on total cost? For example:

1. Does the phrase "maximize the reduction in fossil fuels" in Section 269-27.2(b) allow the Commission to establish a quantity goal, determine the rate necessary to satisfy that goal, and impose that rate regardless of how high the rate is and regardless of total cost?

2. Does the "maximize" phrase mandate that result?

3. If you believe the "maximize" phrase mandates that result, what effect does the discretionary term "may" have on the Commission's obligation?

4. Can the Commission determine a required quantity for the utility to purchase, and then set the rate at whatever level is necessary to attract that quantity? Would such a rate necessarily satisfy the just and reasonable standard?

B. Regardless of any statutory limit on cost, does the Commission have authority to establish a dollar limit on the cost of utility acquisition of nonfossil electricity pursuant to an FiT? What statutes grant this authority?

C. Does this authority to establish a dollar limit apply only to acquisition above the quantities required by the RPS statute?

XI. Seller's Legal Rights:

A. PURPA

1. Does a nonfossil developer have an existing statutory right, under state law or PURPA, to a negotiated PPA? If so, does that right continue even if the Commission establishes FiTs that constitute utility offers to buy at a stated rate, or can the Commission make the FiT the exclusive means by which nonfossil producers sell to the utility? Put another way, if there is a FiT applicable to a particular seller, may the

Commission authorize (or forbid) the utility to negotiate a PPA on terms that vary from the FiT?

2. Can the Commission substitute a FiT for Schedule Q as a means of complying with PURPA? What type of issuance from the Commission would be necessary to demonstrate PURPA compliance?

B. Does HRS § 269-27.2 creates any legal rights in sellers of nonfossil power? For example:

1. Does the phrase "just and reasonable rate" in HRS § 269-27.2(c) mean "just and reasonable" to the seller, or only "just and reasonable" to the consumer? That is, does the phrase "just and reasonable rate" allow a seller to contest a Commission-established FiT on the grounds that the rate is too low or that non-rate terms and conditions are unfavorable?

2. On what specific grounds could the seller contest the rate? That the rate produces a return on equity too low to attract sellers? How would the seller prove this case, to the Commission and to reviewing courts? What data would the Commission have to rely on to insulate its rate decision from judicial reversal? What evidentiary burden does the seller have, to supply facts to the Commission so that the

Commission has the necessary factual support for its decision?

3. If the Commission declined to establish any FiT rates, but instead authorized the utility to self-produce or purchase renewables as the utility deems appropriate, would the sellers have any legal claim against the utility or the Commission? If the answer is no, then do the sellers have any legal right to contest a Commission-established FiT?

C. Assuming the Commission establishes FiTs, may the Commission authorize (or forbid) sellers with existing PPAs to terminate the PPA and enter into an agreement under the FiT? Under what conditions? With what Commission involvement?

D. Hawaii statutes prohibit undue discrimination in the provision of utility service. How does that prohibition apply in the context of FiTs? For example:

1. Can there be different rates for different technologies/sizes/islands? What factual differences are necessary to justify rate differences?

2. Can there be negotiated PPAs that make use of FiT rates but that vary from each other in terms and conditions?

3. Can there be a negotiated PPA for projects that qualify under the scope of an existing FiT?

XII. Utility Role:

A. Does the Commission have the power to restrict the utility's ability to build its own nonfossil generation, such as requiring the utility to refrain from building whenever there is a viable independent seller offering to sell? What findings must the Commission make to support such a restriction?

B. Same question as above, but applied to a utility affiliate selling renewable energy to another utility affiliate.

On May 19, 2009, DBEDT filed a request with the PUC for an extension of time to file the opening briefs. All intervenors to the docket supported DBEDT's request, and both the CA and the HECO Companies expressed no opposition to the request. The basis for DBEDT's request for an extension of time was to explore the possibility of reducing the number of issues in the docket through settlement discussions with the Parties. This was precipitated by DBEDT's discussions with some of the Parties during and after the panel hearings. On May 21, 2009, the PUC issued a letter to all of the Parties in the docket in response to DBEDT's request, extending the filing date for the opening briefs from May 22, 2009 to June 12, 2009, as well as adjusting the schedule for all the remaining deadlines in the docket.

Pursuant to the intent of the requested extension, DBEDT coordinated and facilitated several meetings (May 27-28, and June 1) among the intervenors with the goal of reducing the number of issues. Eleven parties attended one or all of the meetings (in person or telephonically) including HREA, HSEA, Solar Alliance, SOPOGY, Tawhiri, Life of the Land, HDA, Blue Planet, Clean Energy Maui, Zero Emissions LLC, and DBEDT. Given the very limited time that the Intervenors had available to meet, and the number and complexity of the issues as well as the diversity of the interests represented by the Intervenors, the Intervenors were only able to discuss those issues relating to: (1) the role and purpose of FiTs; (2) net energy metering; (3) non-bid PPAs; (4) eligible resources or technologies; (5) total target goals in terms of total MW purchases through FiTs; (6) some pricing principles; and (7) interconnection standards, procedures, and cost allocation. While the Intervenors were not able to reach consensus on all of the above issues, they were at or nearing agreement in principle on some of these issues, so that on June 3, 2009, DBEDT coordinated and facilitated a meeting between the Intervenors and HECO, to discuss whether all of the Parties could reach agreement in principle on those issues. DBEDT would like to note that there was genuine effort and desire by the Parties[3] to reduce the issues through settlement discussions. However, more time is needed to discuss and explore the issues together. It is the intent of the Parties to continue these discussions after the filing of the post hearing opening briefs to try to reduce the issues and to help provide the Commission with information and record evidence to make an informed decision relating to the general principles of a FiTs program in HECO's service territories.

The following section sets forth DBEDT's discussion of, and positions on the major subject areas and questions addressed in this proceeding listed above.

## DBEDT's DISCUSSION AND POSITION ON THE EIGHT SUBJECT AREAS ADDRESSED IN THE PANEL HEARINGS

**I. Given the four existing renewable energy producer options (Schedule Q, net metering, competitive bid, and non-bid PPAs), what contribution would FiTs make toward achieving Hawaii's energy goal?**

**A. DBEDT's Position on the Role of FiTs in Achieving Hawaii's Energy Goals and whether there are gaps in the present procurement method.**

DBEDT believes that the role of FiTs is:

1. To accomplish the HCEI and State energy goals to move decisively and irreversibly away from imported fossil

[3] Only one Party stated that he does not intend to settle on any issues except for those that are consistent with his proposal.

fuel for Hawaii's energy source and towards indigenously produced renewable energy;

2. To stimulate the rapid development of renewable energy in Hawaii; and

3. To accelerate the pace of acquisition of renewable energy by the HECO Companies in order to reduce Hawaii's dependence on imported fossil fuel.

The PUC's Order to examine the implementation of feed-in tariffs in the HECO Companies' service territories cited the Energy Agreement ("Agreement") entered into between the State of Hawaii and the HECO Companies on October 20, 2008 under the auspices of the Hawaii Clean Energy Initiative ("HCEI"). The Energy Agreement between the State and the HECO Companies is a commitment to accelerate the addition of new renewable energy resources and technologies into the HECO Companies' generation portfolio, to promote greater energy efficiency and demand-side load management programs, as well as to promote and facilitate customer-sited and third-party owned renewable energy generation, in order to help achieve the HCEI clean energy and energy independence goals.

Panel I of the panel hearings in the docket addressed the need for and the role of FiTs towards encouraging renewables given that there already exist four options for renewable energy producers in Hawaii: Schedule Q, net energy metering, competitive bidding, and non-bid PPAs. DBEDT submits that the need for, and the role of FiTs in promoting and encouraging more renewables, as required in Hawaii's energy transformation, is created and made imperative by the following evidence:

1. Hawaii's current heavy dependence on imported fossil fuels for over 90% of its electricity generation, despite the abundance of renewable resources in the State and the existence of four procurement methods for purchasing renewable energy by the HECO Companies. The HECO Companies' RPS report for 2007 indicated that only 9% of the total sales were supplied by renewable energy, a major proportion of which were from MECO and HELCO. On Oahu, which accounts for approximately 80% of the total kilowatt-hour sales of the HECO Companies, only 4% of HECO's sales (Oahu) were supplied by renewable energy, and 96% were supplied by imported fossil fuels.
2. The existing procurement methods are inadequate in increasing the development and integration of renewable energy in the HECO Companies' system, especially on Oahu. In response to the requests made during the panel hearings, the HECO Companies submitted Supplemental Information on May 8, 2009, relating to the list of renewable energy projects purchased and integrated into the HECO systems in the last three years, among other

things. The HECO Companies' submission shows that HECO, which serves the island of Oahu, and accounts for approximately 80% of the electricity load in the State, signed only <u>one</u> purchased power agreement for a renewable energy project (with a capacity of only 300 kW). This PPA was signed in November 2007 and is still not in service. HECO's only other renewable purchased power agreement is with H-POWER, and that was signed over two decades ago (in 1986).

3. Since the implementation of the competitive bid process in 2006, only one RFP has been issued by the HECO Companies to date, and only for Oahu. No RFPs have been issued for either HELCO or MECO. As confirmed by HECO during the panel hearings, the bid process requires an inordinate amount of time and resources to prepare and execute.[4] This sole RFP took HECO over two years to prepare, and it remains to be seen if and when this RFP will result in a signed PPA with a winning bidder.

The above information provides compelling evidence that there are gaps and suboptimalities in the present procurement process for renewable energy that make FiTs necessary to achieve Hawaii's energy goals. Given Hawaii's excessive dependence on imported fossil fuel, despite the abundance of renewable

[4] Panel Hearings Transcripts, April 13, 2009, Vol. I, Page 36.

resources in the State and the existence of four renewable resource procurement methods, there is clearly an urgent need to implement FiTs in Hawaii if we are to break our dependence on imported fossil fuels.

DBEDT believes that feed-in tariffs (FiTs) are an effective and critical mechanism for achieving Hawaii's clean energy and energy independence goals for the following reasons:

(1) FiTs are necessary in promoting and encouraging the accelerated development of renewable resource-based electricity generation to reduce Hawaii's dependence upon imported fossil fuels by providing clarity, predictability, certainty, and stability to the purchased power rates (and therefore to the developer's revenue stream) paid by the HECO Companies for purchases of renewable energy.

(2) FiTs provide a clear, transparent, and streamlined utility procurement and interconnection process, and when designed appropriately, offer a superior alternative and complementary method to the current utility procurement methods. The competitive bid process, adopted in December 2006, applies to renewable generators with a minimum capacity of 5 MW for Oahu (2.72 MW for MECO and HELCO), and there are no clear procurement rules for the smaller renewable generators below this minimum capacity threshold size. As mentioned earlier, only one RFP has been issued by the HECO Companies under the bid process to date,

and it remains to be seen whether or not this sole RFP will result in any signed PPA.

Furthermore, the utility procurement of renewable generation that meets the minimum capacity size thresholds without a utility-issued RFP will require a PUC-approved waiver from the competitive bidding framework, for which only the utility can apply or petition. Clearly, the utility not only drives and controls the renewable procurement under the competitive bid process, as well as under the non-bid PPAs, but also controls the interconnection process, which lacks transparency and clarity as evident during the panel hearings.

(3) FiTs eliminate the need for a long contracting process, which ultimately reduces the developer's and the utility's costs, benefiting the ratepayers in the long-run. Under the competitive bidding framework, a renewable resource producer must compete in the utility's bid process and obtain PUC approval, which normally takes a considerable amount of time and resources under a drawn-out procedure with an uncertain outcome that may in any event represent an unacceptable economic hurdle to the renewable resource producer. Similarly, the non-bid purchase power contracting process has the same time-consuming and resource-intensive contracting process with uncertain outcome that inhibits the development of a renewable resource market, as demonstrated by Hawaii's heavy dependence on

imported fossil fuels for power generation despite the abundance of renewable resources in Hawaii. For instance, a geothermal energy producer with an existing PPA with the utility has been negotiating for several years now to expand the purchased capacity for an additional 8 MW under that existing PPA with no progress to date.

More evidence of the inadequacy and gaps in the existing procurement process is the fact that at the time the Energy Agreement was signed, contract negotiations with several projects (either grandfathered in or waived from the bid process) were in progress. To date, three of these projects, with a total combined capacity of approximately 35 MW[5], have been denied extensions of time to complete and file their term sheets, effectively terminating contract negotiations. HECO may consider bringing these projects back to the drawing board by issuing an RFP under the bid process. However, this RFP bid process will not ensure that these projects will bid, and even if they do bid, it is uncertain whether the RFP will result in a signed PPA with any of these projects. DBEDT believes that FiTs would offer an effective, efficient, and transparent mechanism for the utilities to pursue, integrate, and bring these and

[5] Energy Agreement, October 20, 2008, projects identified at 7-8 (Pulehu Biomass (6 MW), Hamakua Biomass (25 MW), and Na Makani (4.5 MW)).

similar projects on-line as desired by the Parties in the Agreement.

(4) FiTs help create a market that increases RPS-eligible energy resources and projects with inherent flexibility so that they can be designed to encourage the development of specific forms of renewable resource generation, or renewable generation at specific locations where they could be most valuable to the utility (i.e., aréas that are not transmission constrained).

(5) FiTs, like the net energy metering statute, are open to all who meet the eligibility requirements, terms, and conditions provided and specified in the FiTs tariff, which helps encourage and promote renewable energy development. FiTs create a renewable energy market environment with transparent procurement rules that are not driven or controlled by the utilities as the competitive bid process and the non-bid PPAs are.

**B. DBEDT's position with regards to the four (4) existing procurement methods is summarized below:**

1. Schedule Q

Schedule Q applies to power purchases from small qualifying facilities with capacity of 100 kW or less, and is based on the utility's "avoided cost". It was first implemented in the early 1980s as a result of the Public Utility Regulatory Policies Act ("PURPA") passed in 1978 by the U.S. Congress as part of the National Energy Act. PURPA was aimed at promoting greater use of renewable energy. This law was aimed at developing a market for non-utility electric power producers (NUGs) using non-fossil fuels, and for cogeneration, and required the electric utilities to buy power from these producers at the "avoided cost" rate, which was the cost the electric utility would incur were it to generate or purchase from another source.

DBEDT recommends that FiTs replace the HECO Companies' future procurements from small qualifying facilities currently acquired through Schedule Q for those renewable resources or technologies that qualify or are covered under FiTs. Additionally, the existing Schedule Q contracts for FiTs-qualified renewable resources and technologies without fossil-fuel components should be provided the option to transition over to FiTs. HECO also proposes that existing Schedule Q generators should have the option to opt-in to the feed-in tariff, as articulated by the utility during the panel hearings.[6]

During the hearings, there were questions raised as to whether it makes sense to give existing Schedule Q generators the same FiTs rates that are designed to attract new renewables. DBEDT believes that it is reasonable and prudent to extend FiTs to existing Schedule Q generators, and to allow these existing Schedule Q generators the option to transition to FiTs, for the following reasons:

[6] Panel Hearings Transcript, April 13, 2009, Vol. I, page 167.

(1) FiTs should be designed to promote and accelerate renewable power generation in Hawaii to the maximum extent possible. This includes attracting new renewable projects as well as retaining existing projects and to the extent possible, even promoting the expansion of cost-effective existing renewable projects.

(2) Since the purchased power rates for Schedule Q are based on the utilities' avoided cost, which is currently based on the fossil fuel price, the benefits of extending FiTs to existing Schedule Q generators will more likely offset the additional costs, if any, that may result from such extension. FiTs effectively de-link the utility's purchased power costs under Schedule Q from the volatility of fossil fuel prices, which benefits the ratepayers in the long-run.

(3) Although Schedule Q has been in effect since the early 1980s, HECO indicated during the panel hearings that there are only about 5 existing Schedule Q contracts, and all are located on the Big Island (HELCO)[7]. HELCO's total purchased power cost for these Schedule Q contracts is only about $29,200 based on HELCO's test-year 2006 submittal in Docket No. 05-0315[8]. HECO and MECO do not have Schedule Q contracts currently in place. Based on the above factual information from HECO, the potential

[7] Panel Hearings Transcript, April 13, 2009, Vol. I, page 29.
[8] Docket No. 05-0315, HELCO-WP-545, page 1 of 26.

rate impact of providing the existing Schedule Q generators the option to transition to FiTs is negligible, if any.

(4) As agreed to between the State and the HECO Companies in the Energy Agreement, the "HECO Companies will make a request of all existing independent power producers in which purchased power agreements are based on fossil fuel prices to negotiate those contracts to de-link their energy payment rates from oil costs and provide ratepayers with stable, long-term and predictably priced contracts."[9] DBEDT believes that feed-in tariffs offer an effective and efficient mechanism to achieve this commitment between the parties in the Energy Agreement.

An issue related to the elimination and replacement of the Schedule Q procurement method with FiTs is whether such elimination violates PURPA, which requires utilities to purchase from small qualifying facilities and cogeneration facilities at the utilities' avoided cost, whereas the FiTs rates that are contemplated in this docket will be based on a "cost plus" method, not on the HECO Companies' avoided cost. This issue and the related question raised by NRRI during the panel hearings as to whether the Commission has to issue some type of order or directive to demonstrate that FiTs is a PURPA tariff[10] are addressed below, in section IX.

[9] Energy Agreement, October 20, 2008, page 16

[10] Panel Hearings Transcripts, April 13, 2009, Vol. I, Page 162.

2. Net Energy Metering (NEM)

Net Energy Metering is primarily intended to promote customer self-generation rather than to sell power to the utilities. The law is intended primarily to offset part or all of the customer's own electrical requirements, rather than to promote power sales to the utility. NEM provides a mechanism for utility consumers to manage their electricity costs rather than becoming (net) electricity producers to sell power to the utilities. NEM provides an effective incentive for the rapid development of customer-sited renewable resource generation as evidenced by the significant increases in the number of net energy metered customers across all islands since 2001 when NEM first became law. As of 2008, the HECO Companies have a total of 810 net energy metered customers (an increase of 805 from program inception in 2001), providing a total capacity of 6.0 MW (a 5.97 MW increase from 2001). Kauai Island Utility Cooperative (KIUC) has 76 net metered customers as of 2008, with a total combined capacity of 0.97 MW. In fact, the neighbor islands utility companies (KIUC, MECO, and HELCO) were among the top 10 utilities in the nation in terms of solar electric capacity per customer in 2008, which is attributed to the significant increases in the customer-sited systems.[11] The

[11] Solar Electric Power Association (SEPA), Report #05-09, 2008 Top Ten Utility Solar Integration Rankings.

significant increase in the net energy metered customers in the last two years may have been due to the significant increases in the fuel (and electricity) prices, although the market expectation is that the same level of activity will continue in the future as Hawaii consumers become increasingly aware of and sensitive to energy issues and the adverse economic impacts of fuel oil prices increase.

DBEDT's statement of position recommended that the net energy metering statute continue to apply to current and future net energy metered customers with respect to kilowatt-hours produced by the customer-generators that offset part or all of the customer's own electrical requirements, and that the net energy metered customer may sell through the feed-in tariffs any excess kilowatt-hours that remain unused. Section 269-108, HRS, provides that net energy metered customers will not be compensated for annual excess kilowatt-hours produced by the customer generator that remain unused by the customer unless the electric utility enters into a purchase agreement for those excess kilowatt-hours. DBEDT's position is consistent with the provision of the Energy Agreement which "support[s] customer energy payment options through modification of Hawaii's net metering option to include provisions for the sale of <u>excess</u> energy produced by the customer's net metered system on an annual basis and payment of such energy at the feed-in tariff rates."[12] DBEDT believes that FiTs offer a streamlined and transparent mechanism that can be employed by the utility to compensate those excess kilowatt-hours rather than through long drawn-out contract negotiations with uncertain outcomes.

Upon further consideration and discussion with the Parties during the May 27-28, 2009 meetings, and based on the effectiveness of the NEM program todate and the expected efficiency of FiTs, DBEDT supports the position of offering customer-generators the following options as an alternative or enhancement to DBEDT's recommendation: (1) the option to apply for net energy metering as currently provided in Part VI of chapter 269, HRS; (2) the option to apply for FiTs for the entire output of the customer-generator; or (3) the option originally proposed in DBEDT's statement of position (i.e., excess, unused kWh compensated through the FiTs rate). DBEDT believes that offering customers these options will further promote customer self-generation using renewable resources.

In contrast to DBEDT's proposal, the HECO/CA joint proposal recommends closing net energy metering to future applicants once FiTs are adopted and implemented. As articulated by HECO during the hearing, once a feed-in tariff is established for a specific renewable technology, HECO will no longer accept net energy

[12] Energy Agreement, October 20, 2008, item #7 at 12 (underscoring added).

applications for that specific technology.[13] HECO's basis for its proposal is its claim of the subsidy impact of net energy metering. DBEDT believes that HECO's claim regarding the subsidy impact is immaterial relative to the total benefits derived from and provided by the net energy metering program, as demonstrated by the following:

(1) The HECO Companies' Net Energy Metering Status Report for 2008 filed with the Commission on January 9, 2009, reported the HECO Companies' estimated subsidy amount totaled only $212,881 for HECO, $255,345 for HELCO, and $248,433 for MECO, or gross total of only $716,659 for all three HECO Companies, which accounts for only 0.02% of the utilities consolidated annual revenues of $2,853,639,000. It should further be noted that these estimated subsidies are for the year 2008, which reported the most significant increase in the number of new net metered customers.

(2) HECO's claim of subsidy impact can be mitigated by requiring the utilities to more closely align their rates with their cost-to-serve such that mostly or only the energy costs (or variable costs) are recovered from the energy rates, and the fixed costs are recovered from the customer or demand charges. Moving to cost-based rates has been one of HECO's rate design goals for the last several decades, and DBEDT believes the HECO

[13] Panel Hearings Transcripts, April 13, 2009, Vol. I, page 113.

Companies should be required to transition faster to cost-based rates in their next rate case filing, as this will address their subsidy concern relating to net energy metering (regardless of how minimal it is), as well as eliminate or reduce the other intra- and inter-class subsidies embedded in their current rate design. Requiring the utilities to file cost-based rates in their next rate case filing will also eliminate their financial concerns in regard to promoting increased energy efficiency and renewable energy, and further complement or mitigate the need for a decoupling mechanism.

(3) The renewable power produced by net energy metered customer-generators counts toward the HECO Companies' renewable portfolio standards (RPS). NEM is effectively helping the utilities meet their statutorily mandated RPS at the customer-generators' own cost, thereby financing part of the utilities' costs of meeting their RPS. This allows the HECO Companies to avoid some costs of meeting their RPS mandates.

(4) While the HECO Companies may argue that the amount of subsidy increases as the net metered customer-generator size limit is increased or eliminated, DBEDT believes that the benefits derived from or provided by NEM will likewise increase (such as the utility's avoided costs of meeting its statutorily mandated RPS). Further, the utilities' avoided costs will likely more than offset the minimal subsidy.

(5) Net energy metered customer-generators also help reduce line losses, which in turn reduce the utilities' fossil fuel consumption and energy costs, thereby benefitting all ratepayers in the long run.

(6) Net energy metering has proven to be an effective mechanism in promoting customer-sited renewable systems as evidenced by the significant increases in the number of participants in the program, as discussed above. Eliminating a program that has proven to be effective in helping accomplish the State's energy goals -- as is being proposed by the HECO/CA joint proposal -- is a regressive step and is contrary to the HCEI and the State energy goals, and should be denied by the Commission.

(7) HECO's proposal to eliminate NEM will require repealing the net energy metering statute, sections 269-101 through 269-111, HRS, which is not within the Commission's authority.

DBEDT believes that the NEM program is essential in transitioning Hawaii to a clean energy economy, and its continuation as proposed by DBEDT, as well as by all the other Parties in the docket, is reasonable and aligned with the State's energy goal of decreasing dependence on imported fossil fuels. DBEDT supports the recommendation of offering customer-generators the three options described above. In HECO's FSOP, the utility indicated that NEM "should be offered until the first FiT update..., two years after FiT implementation."[14] DBEDT believes that NEM should not be displaced, replaced, or eliminated until the costs and benefits of the program, including the program's effectiveness in promoting customer-sited renewable generation and helping achieve the State's energy goals, are properly evaluated.

3. Competitive Bidding

DBEDT believes that the competitive bidding procurement method, if allowed to continue to apply to larger power purchases by the HECO Companies, needs to be modified to become a more effective procurement tool. The current competitive bidding procurement method, adopted and approved by the Commission in December 2006, applies to utility procurement of renewable capacity of at least 5 MW for HECO (2.72 MW for HELCO and MECO). To date, none of the HECO Companies has successfully negotiated any purchased power contracts under the competitive bid process. As indicated above, since its inception, HECO has issued only one RFP under this bid process. HELCO and MECO have not issued any RFPs for renewable resources under this process. The bid procurement process is very time-consuming and resource intensive, which adds to the project costs. It is completely under the control of the utility from the initiation of the

[14] HECO/CA Final Statement of Position, March 30, 2009,page 15.

process (issuance of RFP) to the completion of the process, which may or may not result in a signed power purchase agreement. Unlike FiTs, which is an open offer to buy or purchase renewable power by the utility, the bid process does not mandate that the utilities acquire or purchase power, and if the utilities choose to issue an RFP, the process does not mandate any timeline as to the length of time to complete the process, from the date of issue of an RFP to the completion and signing of a contract with the winning bidder(s). More importantly, the process does not mandate that the RFP result in a PPA. If this procurement method is allowed to continue to apply to utility purchases of large power, DBEDT recommends the following:

First, each of the HECO Companies must be required by the Commission to file its procurement plan under the competitive bid process once every two to three years. Each company's plan must identify the resource type and size, the RFP and contracting schedule, the transmission and/or infrastructure requirements if any, the estimated costs, and the estimated benefits. Each utility must be required to justify its plan to purchase or not to purchase.

Second, the bid framework should be modified to define the timeline for each procedure in the framework so as to provide some clarity and certainty as to when a winning bid is selected, and when a contract is signed and awarded, from the date the RFP is issued by the utility. The framework, rather than the utilities in their RFPs, should specify the length of time the RFP is posted, the period of time bids are accepted, the time period the utilities review and respond to the submitted bids, the time period when the potential bidders may request additional information if any, as well as the time period designated for any other steps in the RFP and the contracting process.

Third, the Commission may wish to consider increasing the minimum capacity size threshold to 100 MW for Oahu (the same size used in the first RFP issued by HECO in the bid process), as this may be the capacity size that HECO can effectively procure under the bid process. Besides the project size threshold, the bid process may be limited to only specific resources or technologies that the HECO Companies seek to procure for specific reasons, such as for grid stability and reliability, or for base load purposes.

Fourth, the bid framework should be modified to require that the utilities file a report with the PUC when an RFP does not result in a successful purchase power contract with the winning bidder(s), and that depending on the report and information provided by the utility, the Commission may choose to open an investigative proceeding.

Fifth, the bid framework should be modified to include a procedure by which the bidders may file a complaint with the Commission within a certain period of time after the utilities announce the winning bidder(s).

(4) Non-bid Purchase Power Agreement (Non-bid PPAs)

DBEDT recommends that FiTs replace the non-bid purchase power contracting for the procurement of FiTs-eligible renewable resources with capacity size of less than the minimum capacity threshold required under competitive bidding. More specifically, DBEDT proposes that the initial FiTs replace the future utility procurement under non-bid purchase power contracting for FiTs-eligible renewable projects with capacity size of 5 MW or less for Oahu, and 3 MW or less for HELCO and MECO. Like the competitive bid, the non-bid PPAs are not transparent, and there are no clearly defined rules or contracting processes for this procurement method, hence the process is completely under the utility's control. There are no PUC mandated rules, no framework, and no process beyond PUC approval of the purchase power contract.

DBEDT believes that feed-in tariffs will fill a critical policy gap for projects below the MW size capacity threshold of the competitive bidding framework. These relatively smaller renewable power producers could provide distributed benefits and resource diversity to the grid, and FiTs could effectively promote this market. Having one procurement method and process for FiTs-eligible resources is more efficient and more manageable even from the utilities' perspective.

During the panel hearings, questions were raised as to whether it is fair and reasonable to allow existing PPAs to opt-in to FiTs. DBEDT recommends that the option of allowing existing PPAs with FiTs-eligible projects to opt-in to FiTs should be done on a case by case basis subject to Commission approval, and with the following requirements: first, the existing PPA must meet the eligibility requirements of the FiTs tariff; second, that the existing PPA rates are based on the utility's avoided cost which is based on the fossil fuel prices; third, that the existing PPA transitioning to FiTs does not result in a significant rate increase impact on the ratepayers.

5. Utility-owned Projects

Another method by which the HECO Companies can increase their renewable power generation is through utility-owned renewable projects. During the hearing, the HECO Companies indicated their intent to keep open their option to own and develop renewable projects.[15] Currently, HELCO owns a small wind farm and four hydro plants ranging in size from 0.4 to 1.5 MW[16], and MECO also owns a small hydro facility. If the HECO

[15] Panel Hearing Transcripts, April 14, 2009, Vol. II, pages 280 - 283
[16] See www.sustainablehawaii.com/hydroelectric.htm.

Companies are allowed to develop their own renewable energy projects, the costs of such projects could be includable in their ratebase and recoverable in their rates subject to PUC approval.

One of the policy issues addressed in the hearing was whether or not to allow the utilities to own and develop their own renewable energy projects. Given the small size of the system and the limited amount of renewable resources that it could take, which may require imposing a cap on the total amount of renewable power purchases through FiTs, allowing the utilities to own and develop their own renewable energy projects effectively allows the HECO Companies to compete for the limited renewable energy market. This could deter the in-flow of outside capital investments to Hawaii. The utilities' participation in the market will likely result in a conflict of interest, since they control all grid and system information, the interconnection process, and the queuing procedure. Some of the Parties indicated their preference to <u>not</u> allow the utilities to develop their own renewable projects.[17] Some parties recommended that, if the HECO Companies are allowed to develop and own their renewable projects, then the management and control of the interconnection and queuing process should be transferred to an independent third party.

[17] Panel Hearings transcripts. Vol. II, pages 262 - 286.

DBEDT's initial and final statements of position indicated no opposition to the HECO Companies developing their own renewable energy projects. Based on the concerns raised by the Parties during the hearing, DBEDT now recommends that such an option be subject to Commission approval on a case by case basis. Similar to some Parties' positions, DBEDT believes that if the HECO Companies are allowed to develop their own renewable energy projects, then the Commission should institute a very rigid and robust oversight of the processing of FiTs applications or contracts, the implementation of the interconnection process, and more importantly, a very strict oversight of the queuing process. DBEDT recommends the following to ensure fair play by all market participants:

(1) The Commission mandates a clear procedure on how the HECO Companies will apply the queuing process to their own projects.

(2) The utilities should be required to file their notices of intent and project applications for Commission approval before expending resources to develop, permit, and construct projects. Such notice filings and project applications should include information on how the utility project will affect the third-party owned projects under FiTs that are currently in the queue, the impact on the amount of caps of power purchases under FiTs, as well as the impact on FiTs applicants in the future in

terms of interconnection and queuing. It should also include an analysis that compares costs and benefits of the HECO Company undertaking the project versus procuring such project through FiTs or through the other procurement methods.

(3) Require that utilities furnish information on the list of projects in the queue as well as the status of such projects, including the amount of the cap (if there is a cap) still unfilled, to be made available upon request by interested parties such as the developers.

(4) Require that utilities provide system information (i.e., distribution circuits kV sizes, total loads served, and resource penetration levels) necessary for other market players or developers to assess the market opportunities, to be made available upon request. Access to the same information will help ensure a level playing field between utility-owned projects and third-party owned projects.

Another question related to utility-owned projects is whether or not FiTs should apply to renewable projects owned and developed by utility affiliates, where there is a purchase transaction between the utility and its affiliates. An example of this situation would be MECO developing a renewable project and selling the power generated to HECO (this could become a reality in the future with the development of an inter-island undersea cable). Should such a transaction between a utility and its affiliate occur in the future, DBEDT believes that the FiTs rates should not apply to it so as to prevent the potential for self-dealing, whether perceived or real, as well as to avoid potential conflicts of interest. Also, such transactions should be subject to the same requirements listed above.

**II. What are the physical limitations on the utility's ability to purchase renewables?**

The relatively small size of Hawaii's electric utility systems, and the fact that there are no inter-ties between the island systems, are important considerations in the FiTs design. The purpose of the hearing discussions on this issue is to establish the facts relating to the physical limitations of the island systems that may limit not only the total amount of utility purchases through FiTs (including the project sizes), but also impact curtailment of variable generation integrated into the system, interconnection, and the queuing procedure.

The HECO Companies claim that consideration of the island systems' physical limitations and reliability concerns are the major factors in determining their very limited FiTs proposal. Panel II of the panel hearings was intended to acquire a common understanding of the physical limitations on the utilities' ability to purchase renewables; the methods of measuring and mitigating the reliability effects associated with integrating additional renewable resources in the system; and whether the reliability concerns should be reflected in the FiT design or should be addressed separately through the interconnection standards and other procedures.[18]

HECO asserts that system reliability is a major consideration in the determination of the very small eligibility limits on the FiTs project sizes that they proposed (500 kW for HECO, 250 kW for MECO and HELCO). However, in all of the HECO filings in the docket, the utilities did not provide any factual evidence relating to the physical limitations of the system, nor any quantitative measures of system reliability that they actually used in determining their FiTs proposal. This was evident even during the panel hearings, when HECO admitted that the utilities do not have quantitative reliability goals or security criteria that they use in establishing their proposed project size eligibility limits.[19]

DBEDT would like to note that during the hearing, the efforts of the facilitator as well as the Chair to get factual information from the HECO Companies did not result in any factual information from the HECO Companies. The common theme of the HECO responses to the questions on the reliability standards and/or physical limitations of the system was that the information is not quantifiable. This is the same response

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[18] Panel Hearings Transcripts, April 13, 2009, Vol. I, pages 178-179.
[19] Panel Hearings Transcripts, April 13, 2009, Vol. I, Page 182, Lines 7-20.

provided by HECO in its response to several information requests from the PUC as well as from some of the Parties in the docket. As a matter of fact, when queried by the facilitator during the hearing, the HECO witnesses were not even able to define what they meant by "reliability", used by the HECO Companies as the basis for their limited proposal in terms of project size. Furthermore, the HECO Companies were also unable to provide the "reliability goals or standards" that they had in mind and supposedly used as the basis for developing the eligibility limits in terms of project size as well as technology exclusions for their FiT proposal. The HECO Companies have not been able to establish a valid rationale for their proposal, much less connect their very limited FiTs proposal to any reliability or security criteria or standards that they supposedly used in the determination of their proposal.[20] A review of the transcripts further indicates that HECO's proposed limited project sizes are based more on their claim of standardizing the interconnection procedure rather than on the physical limitation of the system or reliability concerns.

DBEDT believes that if there is a party in the docket who would have the factual and accurate information on the physical limitations of the system, system reliability goals, and system security criteria and measures, that it would be the HECO

[20] Panel Hearings Transcripts, April 13, 2009, Vol. I, pages 182-189; 197-207.

Companies. But as the records of the proceedings show, even the HECO Companies do not have factual, quantifiable information to support their claims regarding the physical limitations of their own systems, nor any quantified reliability standards or goals that they supposedly used to determine the very limited project size they proposed.

DBEDT recommends that the Commission order the HECO Companies to file the following information to help accurately determine the project size limits that each island system can accept or integrate in the system:

(1) List of distribution circuits by island, including each circuit's location, kV size, peak load, renewable resource penetration, number of customers served, range of customer's kW demand served, daily average total customers' kW load served, and the daily average minimum kW load served for the last 12 months.

(2) For HELCO and MECO - the total hourly load profile of the current intermittent renewable resources in the system as compared to total hourly load served by the systems, for at least the last 12 months.

(3) The amount of must-run utility-owned generation during minimum load conditions and the criteria used to determine these must-run utility-owned units.

(4) The frequency (i.e., number of times) and duration (i.e., number of hours) of curtailment of the existing variable generation on Maui and the Big Island for at least the prior 12 months, and the basis or reasons for the utilities' decision to curtail (i.e., the amount of renewable power being produced versus the minimum loads to serve and the amount of must-run generators on line at the time; the potential system problem that would have occurred without curtailment; and the voltage and frequency variations outside the range allowed by the utilities' tariff Rule 2).

(5) The target reliability goals for each island in terms of system average interruption frequency (SAIF), and the system average interruption duration (SAID), feeder average interruption frequency (FAIF), feeder average interruption duration (FAID), and any other service quality performance indices or system security indices that the HECO Companies measure and/or track as a matter of service performance and operations standards.

(6) The number and duration of power outages (system-wide and localized outages) on Maui and the Big Island, during the last 24 months, and how many of these outages were due to any of the variable renewable energy producers in the MECO and HELCO systems.

DBEDT recommends that the HECO Companies be required to file the above information with the Commission at least four weeks before the settlement discussions among the parties scheduled to begin in August 2009 pursuant to the Commission's letter issued on May 21, 2009 amending the procedural schedule in this docket. DBEDT also recommends that the Commission order the HECO Companies to commission a third-party study of each island's grid (Maui, Big Island, Oahu) to determine how much renewable power the current system can accept, and what system upgrades are needed for varying increases in the amount of renewable power that the system can accept (i.e., increase by 25%, 50%, 75%, 100%), and the costs of such upgrades. DBEDT recommends that the utilities be ordered to file the results of this study at least six months before the first Commission update of the initial FiTs.

**III. What are the appropriate criteria for eligibility to sell under FiTs tariffs?**

During the hearing, the discussion on the criteria for eligibility under FiTs included interconnection feasibility, technology maturity, Hawaii experience, effect on reliability, geographic dispersion, and permitting uncertainties or certainties. These types of eligibility criteria appear to generate the differences in the Parties' positions relating to qualified technologies and sizes.

DBEDT recommends that: (1) the eligibility criteria under FiTs should focus on the resource type and project size; (2) although interconnection standards and procedures are required and necessary elements under FiTs, they should not define or determine what resource types or technologies should or should not be eligible under FiTs; (3) project permitting is the responsibility of the project developer and while the queuing process may require completion of some project milestones (such as completion of all permitting requirements), permitting *per se* should not be an eligibility criterion for qualifying projects under FiTs; and (4) HECO's claim for potential accounting issues relating to purchased power should not be used as a basis for the FiTs design. As discussed during the panel hearings, such potential financial impacts ultimately relate to cost recovery and ratemaking issues which should be addressed in the HECO Companies' rate case filings, and therefore should not be used to define eligibility criteria or requirements for FiTs. Furthermore, such accounting issues are germane not only to power purchases through FiTs but may result generally from purchased power from all of the procurement methods. Additionally, HECO is not completely certain what specific accounting issues will result from power purchases through FiTs.

The following section provides DBEDT's detailed discussion and position on the eligibility criteria for FiTs, including resource or technology types and project size.

**DBEDT's Proposed Eligibility Criteria:**

Resource or technology type

DBEDT proposes that Hawaii's initial feed-in tariffs should be extended to all proven, commercially available and RPS-eligible renewable generation resources and technologies which have relatively established operational experience in the HECO Companies' service territories. Based on these criteria, DBEDT's opening and final Statements of Positions proposed that the FiTs-eligible renewable resources and technologies include wind, solar (PV and CSP), hydro, biomass, biogas, and geothermal.

While there appears to be general agreement among the Parties in the docket that wind, solar (PV and CSP), and hydro are the appropriate resources to include in the initial FiTs program, there were some discussions during the panel hearings about the reasonableness of including biomass, biogas, and geothermal in the initial FiTs offering. During the hearings, one of the Parties in the docket (a renewable developer) suggested not including biomass in the eligible resource under FiTs due to the difficulties with, and the lack of information on the different technologies relating to biomass (including those relating to waste-to-energy), as well as the difficulty in predicting the costs of the renewable fuel supplies be they waste or wood chips or other bio-fuels.[21] HECO has indicated considering biomass as one of the resource types to include under FiTs, depending on additional information that the other Parties in the docket may be able to provide.

Similarly, there were discussions during the panel hearings on whether or not to include geothermal in FiTs due to the potentially large project sizes as well as the limited number of geothermal projects that may come about, and the long time line required to permit and develop a geothermal project. DBEDT's position on including biomass and geothermal as an eligible resource in FiTs is based on the fact that these are proven and mature technologies, and that Hawaii has extensive experience with these technologies given the PPA with H-Power since 1986 and with PGV since 1993. Also, PGV has been negotiating with HECO to expand the capacity of its existing PPA for an additional 8 MW for several years now, yet to date that renegotiation is still in limbo. DBEDT views FiTs as a long-term procurement method, and if biomass and geothermal are not included in the initial FiTs offerings by the utilities, DBEDT

[21] Panel Hearings Transcripts, April 14, 2009, Vol. II, page 80.

recommends that they be considered in future updates of the FiTs program along with all other RPS-eligible resources.

DBEDT does not believe that FiTs should focus on non-commercial technologies or technologies that are not market ready. Offering FiTs to non-commercial or non-market ready renewables or technologies raises policy issues including the reasonableness or prudency of having the utility ratepayers pay for or effectively fund the R&D costs of such projects with uncertain outcomes. Given Hawaii's already high electricity rates, DBEDT does not believe that Hawaii ratepayers should be further burdened with financing R&D costs of non-commercial, non-market-ready renewable projects or technologies. The costs of commercialization of non-market ready technologies may be better shouldered by such entities as the national energy laboratories - such as NREL, or Sandia, or similar other entities - but not Hawaii's ratepayers. DBEDT supports encouraging and promoting the development of new renewable resources and technologies to become commercially available and market-ready, but does not believe that it is reasonable to have Hawaii's ratepayers bear that cost through the FiTs program.

DBEDT also recommends that FiTs in general should apply to only renewable resource-based technologies (i.e., renewable projects with no fossil fuel component), which is consistent with DBEDT's position on the purpose of FiTs, namely to promote and accelerate the use and development of renewable resources to achieve the HCEI's goal of transitioning Hawaii to at least 70% renewable energy-based economy by 2030. Extending FiTs to technologies using up to 49.9% fossil fuel as articulated by the HC&S witness during the hearing[22] is contrary to the State's goal of reducing Hawaii's dependence on imported fossil-fuel and will instead perpetuate this dependence for the life of such technology, which could last for several generations.

Project Sizes

DBEDT proposes that the initial FiTs apply to renewable generation with capacity size up to 5 MW for Oahu, and up to 3.0 MW for HELCO and MECO. DBEDT believes that these project sizes, especially the 5 MW for Oahu, are reasonable and appropriate based on the following:

a. These project sizes will allow a bigger pool of market participants, resulting in potentially greater diversity of the renewable distributed generation portfolio in HECO's service territories.

b. A greater number of relatively small distributed generation will potentially provide system benefits by helping replace central generation stations and improving grid operation and reliability as they are dispersed in different locations in the system grid.

[22] Panel Hearings Transcripts, April 14, 2009, Vol. II, page 161.

c. Replacing central generation stations with renewable distributed generation will also reduce line losses, which in turn reduces the imported fossil fuel used by the HECO Companies. These line losses are reported at 9.56% for MECO, 11.17% for HECO, and 11.96% for HELCO, translating to a total of approximately 699,400 MWH and consuming approximately 1,259,000 bbls of oil.[23]

d. These project sizes will attract more local market participants or developers and will result in general economic benefits to the State.

e. These project sizes are easier to site relative to much larger project sizes as proposed by the other Parties.

f. These proposed project sizes do not overlap or conflict with the minimum capacity size thresholds of generators for the existing competitive bid process, while at the same time filling the procurement process gap for those projects below the capacity size threshold for the bid procurement process.

g. DBEDT's proposed 5 MW project size limit for Oahu is reasonable based on HECO's system load and the almost negligible penetration of variable generation in its system. HECO accounts for approximately 80% of the total kilowatt-hour sales in the State, serving a system peak

[23] Based on 2007 generation and sales reported in FERC Form 1 Report.

load of 1186 MW in 2008. To date, HECO's only variable generation in its system is the small net energy metered customer-generators (mostly if not all PVs) with total capacity size of only 2.849 MW, much less than the limit of 1% of system peak load which totaled 11.9 MW in 2008[24]. Based on this almost negligible penetration of variable generation in HECO's system, it is highly unlikely that the proposed 5 MW project size will affect HECO's system reliability, however that "system reliability" is measured.

h. Compelling information that supports the reasonableness of DBEDT's proposed 5 MW project size for FiTs eligibility for Oahu is based on the total non-coincident peak demand (NCD) at distribution voltage level in HECO's system. One limitation raised by the HECO Companies that affects the project size eligibility is the size of the total customers' peak load or demand on the distribution circuits. The utility proposes to use the criteria of 15% of the distribution circuit peak demand as a trigger for requiring an additional interconnection study to interconnect a renewable project into the system. It should be noted that almost all of

[24] 2008 Net Energy Metering Status Report, HECO Companies, January 9, 2009. Page 4 of 5.

HECO's 296,200 customers are served at the distribution voltage level. There are only four large customers who are served at the transmission level, based on information provided by HECO in its test-year 2009 rate case in Docket No. 2008-0083.[25] A rate class's non-coincident kW demand is the sum of the maximum demand of the individual customers in that rate class. Based on information submitted by HECO in its rate case, the total non-coincident demand of all rate classes was 26,215 MW.[26] This total NCD is a close approximation of the total peak loads on the distribution circuits, and is 5243 times higher than the 5 MW project size proposed by DBEDT for HECO. HECO's criteria of 15% of distribution peak demand for interconnecting renewable energy will allow the HECO grid to interconnect a total of approximately 3,900 MW of renewable projects (15% x 26,215 MW).

On page 32 of HECO's final statement of position, HECO indicated that the load on HECO's 12 kV circuits ranges from 400 kW to 13 MW. The upper limit of the range is almost 3 times the proposed 5 MW project size for Oahu. DBEDT would also like to note that HECO's distribution voltage levels as defined in HECO's Rule 2 tariff include 25 kV where relatively larger

[25] Docket No. 2008-0083, HECO-WP-302, Page 109 of 155.
[26] Docket No. 2008-0083, HECO-WP-2203, Page 2 of 70.

customers receiving service at distribution voltage are most likely served. HECO did not indicate the size range of loads served at 25 kV circuits. Additionally, DBEDT believes that renewable energy purchased by HECO through FiTs should not be limited to only those projects that are interconnected at the distribution voltage level. The relatively larger projects that are closer in size to 5 MW may have to be interconnected at sub-transmission level.

DBEDT also proposes that future updates to the FiTs designs should consider extending FiTs to all RPS-eligible resources, and to relatively larger project sizes than the initial 5 MW recommended by DBEDT. Based on the above information, there is merit in the Commission evaluating increasing the project size up to 20 MW for some resource or technology types for Oahu, especially for firm renewable generation resources such as biomass and geothermal, in the first update of FiTs.

**IV. What decisions are necessary to ensure that FiT rates are just and reasonable, as required by Hawaii law?**

DBEDT recommends the following pricing principles in the determination of the FiT rates:

(1) The FiT rates should be differentiated by island, by resource type and technology, by project size, and by interconnection costs.

(2) The FiT rates should be based on the project cost plus a reasonable rate of return on capital investment. The project cost is defined to include:

(a) The design, permitting, and construction costs, including labor and materials costs;

(b) Land cost or actual cost of site acquisition;

(c) Metering costs incurred by the project developer;

(d) Operation and maintenance labor and non-labor costs including renewable fuel costs, if any; and

(e) Other project development or operational costs such as taxes, interest payments, and monthly land rents or leases.

(3) The project development cost should be adjusted by any applicable State and/or federal tax credits or tax policies, rebates, or development or investment incentives for renewables that exist when the FiT rates are determined. Adjusting the project development costs for such tax credits, tax policies, rebates or incentives for renewables is consistent with the inclusion of the taxes incurred in the project development cost used in the determination of the FiT rates. The FiT rate however should not be automatically adjusted for any <u>future</u> tax credits, rebates, or incentives for renewables. Instead, DBEDT recommends that the FiT tariffs include a provision in the tariffs' terms and conditions that the FiT rate will be adjusted

for any applicable changes to the tax credits or policies, rebates or incentives for renewables that may be established or instituted in the future.

(4) The determination of the FiT rates should include the interconnection costs incurred by the project developer. As proposed by DBEDT, the FiT rates should vary by interconnection costs in consideration of the fact that the interconnection requirements may vary by project size and/or the voltage where such project may interconnect to the system (i.e., at distribution voltage or at sub-transmission voltage level).

Clear delineation of the interconnection costs responsibility of the utility and the resource project developer should be included in the interconnection standards and procedures. DBEDT proposes that the costs of interconnection requirements on the utility side of the interconnection point should be borne by the utilities, and the costs of the interconnection requirements on the project side of the interconnection point be borne by the project developer. DBEDT also proposes that energy storage and other utility integrating technologies which provide ancillary services should be owned and paid for by the utilities and recovered in the rates subject to PUC approval. This will allow the utilities to grow their transmission and distribution rate base and compensate for the potential lack of growth in their generation plant investment or generation rate base. Alternatively, these firming technologies may also be acquired through FiTs with appropriate prices, terms and conditions designed specifically for grid integration and ancillary services.[27]

(5) The operation and maintenance labor and non-labor costs included in the determination of the FiT rates should be adjusted for some estimate of inflation to reflect the changes in such costs over the contract term. Reflecting some estimates of the future changes in the project's operation and maintenance cost will provide the project developer just and reasonable FiT rates to recover its cost.

(6) The FiT rates should neither be based on nor guided by the HECO Companies' avoided cost, which is generally based on the price of imported fossil fuel. De-linking the HECO Companies' purchased power costs from the price of imported fossil fuel, which has exhibited significant volatility in the past and will likely repeat in the future, caused by market conditions that are beyond the utilities' control, provides economic benefits to Hawaii's ratepayers in general.

(7) The preferred cost data is the cost of Hawaii-based or Hawaii-specific projects. To the extent that Hawaii-specific cost data is not available for most project size and technology

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[27] Energy Agreement, October 20, 2008, at 9. The Agreement indicates that these technologies may be acquired with PPAs.

combination and by island, secondary data sources for industry costs may fill the information gap for setting the initial FiT rates. The data from secondary sources however should be reasonably adjusted to reflect the Hawaii market. The cost and/or purchase power rates of existing renewable projects in Hawaii may be used to test the reasonableness of the secondary sources of data. Information provided in unsolicitated proposals from project developers received by HECO Companies may be used by the Commission in assessing the reasonableness of any proposed FiT rates and aid in the Commission's decision making without necessarily violating the confidential nature of such information. The information submitted to the Commission by the intervenor-developers in the docket also provides market-referent information that the Commission may use in assessing the reasonableness of any proposed FiT rates.

(8) As stated in DBEDT's final Statement of Position (FSOP), the renewable energy purchased by the HECO Companies through FiTs should count toward the utilities' renewable portfolio standards (RPS). This means that the renewable energy purchased through FiTs shall include the renewable energy credits (RECs) or green attributes of such purchased renewable energy. While Hawaii does not currently have so-called "RECs market" and the statutorily mandated RPS goals are stated in terms of kilowatt-hours produced from renewable resources, DBEDT

understands that the green attributes of a renewable resource cannot be double counted in RECs market (i.e., the RECs or green attributes of renewable energy that has been counted toward an RPS goal cannot be sold again in a RECs market.) DBEDT recommends that the determination of the FiTs rates should not impute any additional value for the green attributes of the renewable energy purchased by the HECO Companies through FiTs. The green attributes of the renewable power being purchased through FiTs is a resource characteristic that makes the project eligible under the FiTs program. The determination of the FiTs rates is based on the project cost plus reasonable return, and it is not a "value-based" method. The presumption of a future market for RECs should not be used as a basis for imputing any value for RECs in the determination of the FiTs rates, as there is no evidence in the record as to the basis of such a presumption or how such a market would value RECs. The cost-based determination of the FiTs rates already compensates the developers for the cost of the project, and DBEDT does not believe that they should be compensated for some presumed value of the project's green attributes based on an expectation of some future market for such attributes unbundled from the kilowatt-hours produced by the project.

(9) The determination of the FiT rates should include or account for project performance through an estimate of capacity

factor in the determination of the revenue stream for each resource or technology type.

(10) Utility curtailment of the power produced and delivered by a project to the utility grid will impact the project's revenue stream. DBEDT recommends that the FiTs terms and conditions include specific provisions for a reasonable, cost-effective, and non-discriminatory curtailment provision. Curtailments beyond those due to conditions beyond the utilities' control, such as system emergencies due to acts of nature, should not be reflected or included in the FiTs rates. However, curtailments due to reasons such as minimum load conditions or due to must-run utility-owned generating units should be reflected or considered in the determination of the FiTs rates. DBEDT proposes that such curtailments be accounted for in the determination of the FiT rates by an adjustment to the capacity factor used in the determination of a resource revenue stream in the FiT rates calculation.

(11) FiTs costs-benefits should be assessed over the entire term of the FiTs program. Estimates of the cost impact of feed-in tariffs may be determined when the target amounts and FiTs rates are set. The cost impact should and must be compared with the benefits of implementing FiTs to promote and accelerate the increased development of renewable resources and attendant economic and environmental benefits of the reduction in Hawaii's

oil imports. Cost impact calculations should also consider the risk of committing to additional investment in oil-based electricity generation over the lifetime of this facility both in terms of market and price volatility.

## V. What non-rate terms are necessary to make FiTs just and reasonable?

DBEDT's position on the non-rate terms necessary to make FiTs just and reasonable are discussed in the following section.

1. Contract Term

During the Parties' settlement discussion meetings scheduled March 18-19, 2009 pursuant to the PUC-approved procedural schedule, the Parties agreed that the appropriate contract term for FiTs design is 20 years. The Parties' settlement agreement on the 20-year contract term was based on the recognition that a major benefit of FiTs is providing certainty and stability to a project's revenue stream which facilitates and reduces the project's financing costs to the ultimate benefit of the ratepayers; that the 20-year term is reflective of the service life of the renewable resources and technologies being included in the initial FiTs; and the 20-year term is used in most of the existing FiTs programs that have been proven to be effective and successful. During the panel hearings, several of the intervenor-developers confirmed that the life expectancy of solar resources (PV and CSP) is longer than 20 years, and confirmed that the contract term for PPAs for these technologies has usually been 20 years.[28] For biomass, an intervenor-developer confirmed that some combustion boilers have gone beyond 20 years, and the contract term of their existing PPA is 24 years (1990-2014).[29] Wind technology is designed for a 30-year life, especially as the technology evolves,[30] and the existing Puna geothermal plant has been in-service since 1993, close to 20 years now. Industry information compiled by some national energy laboratories also supports that a contract term of 20 years is generally reflective of the service life of the technologies considered for inclusion in the initial FiTs, such as PV.[31]

Additionally, DBEDT recommends that the FiTs design should include a procedural provision relating to contract termination before the end of the contract term for situations such as non-performance and other, similar conditions relating to the renewable project or technology, especially if the total renewable energy purchases through FiTs are capped. DBEDT also recommends a procedural provision (contract extension option) for the continuation of the contract beyond the 20-year contract

[28] Panel Hearings Transcripts, April 16, 2009, Vol. IV, pages 13-19.
[29] Panel Hearings Transcripts, April 16, 2009, Vol. IV, page 19.
[30] Panel Hearings Transcripts, April 16, 2009, Vol. IV, pages 20-21.
[31] Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-1410E, January 2009.

term when the project or technology is still generating and supplying energy to the utility. A provision in the FiTs terms and conditions may simply state that at the end of the 20-year contract term, the contract may continue on a year to year (or month to month) basis until terminated by a 60-day written notice by either party. Also for clarity, if such a provision is included, any changes to the FiT rates that would apply should be specified with this provision.

During the panel hearings, a related issue was raised by the facilitator regarding who (i.e., the utility or the developer) gets the rights to the power produced by the project at the end of the contract term. DBEDT believes that the project developer owns the project <u>during</u> and <u>after</u> the 20-year contract term. The FiT provides the terms and conditions including the price for the utility purchases of the <u>power produced by the project</u>, and not the utility purchase of the project itself from the developer. The ownership of the project by the developer is not in any way affected by the FiTs tariff, and the developer has exclusive right to the power produced by the project at the end of the contract term. After the contract term, the developer may choose to continue to sell the power to the utility, and the utility may choose to continue to buy the power from the developer at rates specified in the FiT for post-contract term sales if different from the FiT rates during the contract term. Additionally, FiTs are simply another procurement mechanism like the other four existing mechanisms discussed above. None of the HECO Companies' existing PPAs provides for the utilities' rights or ownership to the power produced by these PPA projects at the end of the contract, and it is not clear to DBEDT why FiTs would raise such a question or issue.

DBEDT notes that it does not agree with the presumption made by the facilitator that "Through FiT, eligible technologies and projects will be subsidized by the ratepayer, at least initially, to make them economically viable and encourage them to locate in the State."[32] This statement assumes that a subsidy exists to the extent that the FiTs rates are above the avoided costs. DBEDT does not agree that setting the FiTs rates above, below, or at avoided cost determines whether or not there is a subsidy. For one thing, the presumption made does not define what is meant by subsidy. HECO's definition of subsidy, as used in its proposal to eliminate NEM, is the lost contribution to fixed costs (which as DBEDT has shown above, is negligible and more than off-set by the benefits provided by NEM), which basically refers to the fixed costs embedded in the energy charge that is not recovered by the utility from the net energy metered customers, and are then borne by the shareholders until

[32] Panel Hearings Transcripts, April 16, 2009, Vol. IV, page 36.

the utility's rates are re-set in the next rate case. Secondly, the presumption also does not define what avoided cost is in reference to (i.e., the price of fossil fuel or the cost avoided by the utility for purchasing the renewable power rather than developing its own renewable power), and whether it is the appropriate referent to use to determine whether or not there is a subsidy.

2. Service Contract with the FiTs Tariff

One question addressed by Panel V during the hearing relates to the need for a service contract along with the feed-in tariff or whether the tariff itself contains all the necessary legal rights and obligations. The question was triggered by HECO's concerns relating to the potential accounting treatment of the company's obligations relating to a FiTs program which could impact its credit quality and the company's financial profile.[33] In exploring HECO's concern during the hearing, HECO was asked by the facilitator whether just having a FiT tariff with no contract still raises the same concern or whether it is the existence of the contract that causes the concern. HECO was unable to provide a response during the hearing, and DBEDT assumes that they will include it in their opening briefs.

[33] Panel Hearings Transcripts, April 16, 2009, Vol. IV, pages 88-93.

DBEDT believes that a feed-in tariff will still require a service contract. This issue is addressed below in section IX.

3. Incremental capacity

DBEDT recommends that the FiTs design include a provision relating to incremental capacity. Incremental capacity could include facility upgrades or expansions to FiTs projects.

The Commission could also consider extending this incremental capacity for existing renewable energy generation that does not qualify for FiTs and have only the incremental capacity be eligible for the FiT rates. During the hearing, the HECO Companies indicated that this may be difficult to implement because of the difficulty of measuring the incremental capacity.[34] DBEDT believes that the incremental capacity to an existing renewable generation project can be separately metered, especially with the use of the advanced metering infrastructure (AMI) that HECO is proposing to implement. In the unlikely situation that the incremental capacity to an existing project cannot be metered separately, there are proxy measurement methods that can be used to ascertain the incremental capacity. One such method, where the total project capacity including the existing and the incremental capacity is metered under one meter, is to subtract the existing contract capacity from the total metered capacity on an hour by hour basis to determine the

[34] Panel Hearings Transcripts, April 13, 2009, Vol. I, Pages 99-100.

incremental capacity. Again, DBEDT believes that HECO's proposed AMI will have the capability to meter the hourly (or smaller interval such as 1 minute or 15 minute intervals) output of interconnected renewable generation. DBEDT believes that there are methods to measure or determine the incremental capacity of an existing project and recommends that the FiTs design include a provision allowing FiTs to apply to incremental capacity for FiTs-eligible projects as well as for existing projects with non-FiTs PPAs.

4. Application, technical review, and approval process.

DBEDT's FSOP recommends that the initial FiTs be subject to PUC evaluation and update annually during the initial 5 years, and every two (years) for the next ten years until the PUC deems the FiT design to be sound. DBEDT also recommends that the FiTs design incorporate an annual reporting requirement by the utility to the PUC, as well as an annual reporting requirement by the individual renewable producers to the utility. In contrast, HECO proposes that the first FiT update be made two years after implementation[35]. DBEDT does not object to HECO's proposal provided that the utility files an annual report to the Commission on a calendar year basis, providing the following information:

[35] See, for instance, Panel Hearings Transcripts, April 13, 2009, Vol. I, Page 116.

(a) Number of project applications received by island, by resource type, by project size, and interconnection process (Rule 14H or IRS at sub-transmission level).

(b) Number and status of projects currently in the queue by island, by resource type, and by project size.

(c) Number of projects completed, interconnected, and contract signed by island, by resource type, and by project size.

(d) Total kilowatt-hour purchased through FiTs during the calendar year by island, by project, and by project size.

(e) Total amount in dollars of the power purchased through FiTs during the calendar year by island, by project, and by project size.

(f) Number and duration of curtailments and the reason for each curtailment during the year by island and by project.

(g) Program administration information such as the time spent to complete processing a project application from date of receipt of contract application to interconnecting the project in the system - by island, by resource type, and by project size.

5. Reporting and data requirements from the renewable projects

DBEDT recommends that the FiTs specify an annual reporting requirement from the renewable project developers to report project information to aid the Commission's data gathering for use in the FiTs update. Some specific data requirements include, without limitation:

(a) The cost of project design, permitting, and construction costs, including labor and materials costs;

(b) Financing or capital cost;

(c) Land cost or actual cost of site acquisition;

(d) Interconnection and metering costs incurred by the project developer;

(e) Other project costs incurred in developing and constructing the project;

(f) Tax credits, rebates, incentives received and applied to the project development cost;

(g) Maintenance and operation labor and non-labor costs;

(h) Fuel supply costs (for biomass and biogas projects);

(i) Monthly land or site leases; and

(j) Other operations and maintenance costs.

The periodic reexamination of the FiTs tariff should include the evaluation by island of:

(a) the FiTs rates;

(b) the eligible resources;

(c) the project size;

(d) the level of total project cap, if one is established;

(e) program application and utility technical review process; and

(f) the utility's interconnection standards and process.

**VI. Utility cost recovery: What principle should apply?**

The questions included in this issue include: (1) whether either additions to rate base or assured recovery for the utility appropriate; and (2) how FiT costs are to be allocated to the customers of the three HECO Companies.

Under the Energy Agreement between the State and the HECO Companies, the signatories supported in principle to allow the HECO Companies to include in its ratebase 10% of the total power purchased through FiTs. The Parties to the Energy Agreement[36] know and understand that under the current regulatory framework purchased power costs are expense items and not ratebase items. The concept of including 10% of the total power purchases through FiTs in the utility's ratebase is one of the regulatory changes identified in HCEI, along with implementation of a decoupling mechanism that serves as an incentive mechanism to help break down the barrier to the utilities promoting and accelerating increased renewable power generation. Similar to

[36] DBEDT, CA, HECO Companies.

the decoupling mechanism, this concept of "ratebasing" purchase power expense is definitely different from the traditional and typical ratemaking framework. It should be noted that not all items in the HECO Companies' ratebase are plant or capital investments. Certain non-plant costs are included in HECO's ratebase and conveniently categorized as "regulatory assets".

The signatories to the Energy Agreement agreed that allowing the utilities to ratebase a certain percent of the total power purchases through FiTs, subject to PUC approval will compensate the utilities for the potential zero growth in their generation rate base because of the FiTs program. The HECO Companies however interpreted this concept as compensation to the utility for the financial risks associated with long-term power purchases through FiTs. DBEDT believes that the utilities' concerns relating to the accounting treatment of power purchases through FiTs and the potential financial impact of such accounting treatment is not germane to power purchases through FiTs and are better addressed in the Companies' general rate case filings where such impacts are normally reflected in the determination of the utility's rate of return. The utility power purchases through the other procurement methods, such as the non-bid PPAs and the bid PPAs, must raise the same concerns relating to accounting treatment and financial risks, but these issues or concerns are not addressed in the PUC application filed by the utilities to approve these PPAs. In other words, the application seeking PUC approval of any of the existing non-bid PPAs was not pre-conditioned on the results of the accounting treatment of the PPA. Rather, these financial risks are reflected or factored into the determination of HECO's proposed rate of return in its rate case filings. DBEDT believes that the potential financial impact of the accounting treatment issues raised by HECO relating to the utilities' power purchases through FiTs should be addressed in the companies' respective rate case filings in the determination of the companies' overall cost of capital.

Another mechanism supported by the signatories to the Energy Agreement to break down the barrier to the utilities promoting and increasing their renewable power generation is to allow the HECO Companies to recover the costs relating to power purchases through the FiTs through a Purchased Power Surcharge similar to the current ECAC, subject to PUC approval. The current ECAC mechanism already includes the recovery of the purchased energy costs (i.e., purchase power costs paid for kilowatt-hours purchased), but does not include recovery of purchased capacity costs (i.e., purchased power costs paid for kilowatt capacity). DBEDT recommends that the PUC implement a separate Purchased Power Cost Recovery Adjustment (PPCRA) mechanism (separate from ECAC) that would allow the utilities to recover the costs of their renewable power purchases through FiTs and through the other procurement mechanisms. This cost recovery mechanism may be filed by the utility on a monthly basis like the current ECAC, or quarterly, whatever is deemed appropriate and reasonable by the Commission. DBEDT also recommends that this separate purchased power cost recovery mechanism be subject to PUC review and evaluation at any time for reasons deemed appropriate and necessary by the Commission.

Such a recovery mechanism should recover actual or recorded costs (i.e., actual incurred amount rather than projected costs) and trued-up for the over- or under-recovery resulting from the variations in sales on which the actual costs incurred are recovered. DBEDT believes that allowing the utilities such an automatic cost recovery mechanism will at least put the utilities' renewable power purchases on a level playing field with the utilities' purchases of imported fossil fuel which are allowed automatic cost recovery through the ECAC.

Any other utility costs related to FiTs, such as the administration costs including the application review, interconnection review, cost of interconnection borne by the utilities, and management and implementation of the queuing process should be recovered in each utility's rates through the normal utility rate case filings. Furthermore, ratemaking and recovery issues regarding any financial impact that may result from any potential accounting issues relating to power purchases should also be addressed in the HECO Companies' normal rate case filings, rather than addressing them in this docket or using them as a basis for FiTs eligibility criteria.

With regard to the allocation of FiTs cost to the three HECO Companies (HECO, HELCO, MECO), there are two allocation options: (1) the FiTs costs incurred by each company are recovered from the respective company's ratepayers (i.e., HECO's FiTs costs recovered only from HECO's customers, MECO's FiTs costs recovered only from MECO's customers, and HELCO's FiTs costs recovered only from HELCO's customers); and (2) the total FiTs costs incurred by all three companies are recovered on a consolidated basis (i.e. Total FiTs costs incurred by all three companies ÷ Total kWh sales of all three companies). Both methods have merit. The first method provides cost-based recovery for each island and eliminates any potential subsidization issues between the islands in the future. It is consistent with Hawaii's current ratemaking procedure, in that each island is a separate entity with separate financial accounting and cost-of-service. It is relatively simple and easy to implement.

The second method may be justified on the basis that the RPS statute allows the three companies to achieve their RPS on a consolidated basis, and both HELCO and MECO have been contributing more to the utilities' consolidated RPS than HECO. One can argue that the allowance of consolidated RPS reporting and the higher proportionate contributions of both MECO and HELCO to the consolidated RPS actually results in both MECO and HELCO subsidizing the HECO ratepayers.

DBEDT supports the first method which recovers the FiTs cost incurred by a utility from that utility's ratepayers. However, if the Commission adopts the second method that allows the consolidated recovery of the FiTs costs, DBEDT recommends that this consolidated cost recovery be limited to the recovery of the costs of power purchases through FiTs which are proposed by DBEDT to be recoverable through a purchased power cost recovery adjustment discussed above. No other FiTs-related costs covered in the HECO Companies' rate case filings should be included in the consolidated cost recovery, but should rather be addressed in each utility's ratemaking procedure.

**VII. What are the appropriate processes for accepting and interconnecting FiTs projects?**

This section provides DBEDT's discussion and position on the issues relating to interconnection and queuing.

Interconnection Standards, Procedure, and Costs

As stated in DBEDT's FSOP, DBEDT believes that just and reasonable FiTs require clear, efficient, transparent, and streamlined interconnection rules, standards, and procedures for interconnecting the renewable power generating facility designed to sell power to the utility system. Interconnection rules and standards are critical elements to the success of any FiTs program. These interconnection rules, standards, and procedures must be published and included in the FiTs. Rather than "one rule fits all", some elements of the FiTs interconnection rules, standards, and procedures may differ depending on the project size. These interconnection standards and procedures should be consistent with industry interconnection best practices; they must be clear; they must be transparent; they must be streamlined; and they must be relatively uncomplicated for ease of administration and implementation.

As articulated by the HECO witnesses during the panel hearings, the HECO Companies have two different types of interconnection processes[37]: (1) the tariff Rule 14H for the distributed generation interconnection process at the distribution voltage level, and (2) interconnection requirement studies (IRS) that are typically conducted by the utilities for power purchase agreements. HECO's limited FiTs size proposal only envisions and proposes to use the tariff Rule 14H for interconnecting FiTs projects, as they believe that their small FiTs size proposal will lend itself to standardized

[37] Panel Hearing Transcripts, Vol. IV, page 197.

interconnection processes and requirements. However, as discussed by the HECO witnesses during the panel hearings as well as acknowledged in HECO's proposal, even some projects that meet their limited FiTs size proposal will require IRSs depending on the technology type, location, and renewable resource penetration on the feeder or circuit where the FiTs resource or technology will interconnect. This effectively discredits their claim that their small project size proposal allows standardization of the interconnection process.

The actual experiences of a couple of the Parties with the HECO Companies' interconnection process, specifically with HELCO, amplify the interveners' position (including DBEDT) for the need to have clear and transparent interconnection processes and standards.[38] As indicated by the HECO witness, the company has made a commitment in the Energy Agreement to conduct an evaluation and may propose modifications to Tariff Rule 14H, which they plan to file by the end of June 2009.[39] Given this company's filing plan, DBEDT will reserve providing its comments and suggested modifications to Rule 14H until after DBEDT has had a chance to review the Company's evaluation and proposed modifications to the current Rule 14H. DBEDT believes that Rule 14H, which provides one of the interconnection processes that

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[38] Panel Hearings Transcripts, April 16, 2009, Vol. IV, pages 204-208.
[39] Panel Hearings Transcripts, April 16, 2009, Vol. IV, page 213.

HECO is using, is a critical element in the design of FiTs, and merits a very careful review by the Parties and the Commission.

With regard to interconnection costs, HECO's submittal of supplemental information filed with the Commission on May 8, 2009, included among other things a list of the specific costs associated with interconnection. The list included:

(a) Utility system costs and upgrades - which includes costs associated with:

  (1) new transmission line or infrastructure or upgrades to the existing (transmission) infrastructure;

  (2) procurement and installation of equipment which provides ancillary services to mitigate the adverse effects of variable generation; and

  (3) relay upgrades, setting changes, and protection reviews.

(b) Project specific equipment which include the costs associated with:

  (1) line extensions, substation and transformation equipment;

  (2) equipment installed at the customer site specifically for the project; and

(3) SCADA, control system, and curtailment system specific to the project to allow for system interface and provide control and visibility of the plant to the system operator.

(c) Interconnection Review Study costs (IRSs).

(d) Project risk assessment costs, including costs associated with curtailment studies.

(e) System and feeder studies and technology verification studies by the utility.

The above list of interconnection costs provided by HECO is helpful. DBEDT however would like to recommend to the Commission requiring the utilities to provide more information on what the Interconnection Review Study includes, such as the process, the elements of the project or the system that is "studied"; study methodology or approach used; and the types of information that results from the study. It is also not clear how an IRS is different from the "project risk assessment" and from the "system and feeder studies", or whether these are all parts of the IRS. DBEDT recommends that the Commission require the HECO Companies to provide detailed information on each of these studies.

As noted by HECO during the panel hearings, IRS is the interconnection process that is typically conducted for PPAs.[40] As noted earlier, some projects within HECO's proposed small project sizes may also require IRSs. Clear and transparent information relating to the IRS must be available to the Parties and the Commission to help establish a clear and transparent interconnection process for those projects that may require IRSs, as well as to establish a clear delineation of the interconnection costs responsibility between the utility and the resource project developer to be included in the interconnection standards and procedures for FiTs.

DBEDT proposes generally that the costs of interconnection requirements on the utility side of the interconnection point should be borne by the utilities, and the costs of the interconnection requirements on the project side of the interconnection point be borne by the project developer. DBEDT is still in discussion with the other parties on the allocation of the specific interconnection costs identified by HECO in its submittal of supplemental information as listed above, and will provide its proposal in the reply briefs.

DBEDT also proposes that energy storage and other utility integrating technologies which provide ancillary services should be owned and paid for by the utilities. This will allow the

[40] Panel Hearings Transcripts, April 16, 2009, Vol. IV, page 197.

utilities to grow their transmission and distribution rate base and compensate for the potential lack of growth in their generation plant investment or generation rate base. Alternatively, these firming technologies may also be acquired through FiTs with appropriate prices, terms and conditions designed specifically for grid integration and ancillary services.[41] DBEDT recommends that these prices be separate from the FiTs rates although included in the FiT tariffs.

Queuing

During the panel hearings, the HECO Companies indicated that there are currently no renewable projects in the queue,[42] meaning that there are no backlogs of renewable projects waiting to be processed under the utilities' Rule 14H. This was confirmed by HECO's submittal of supplemental information filed with the Commission on May 8, 2009. The fact that there are no renewables waiting to be processed indicates that either the process is very efficient, such that every renewable that comes forward is processed and interconnected very quickly, or that the procurement system is not working, such that there are very few renewable projects that are able to successfully negotiate a signed PPA with the utilities. Based on the amount of renewable

[41] Energy Agreement, October 20, 2008, at 9.
[42] Panel Hearings Transcripts, April 16, 2009, Vol. IV, page 198.

power in the system, especially on Oahu, one may tend to believe that the latter may be the case.

DBEDT's FSOP recommended that the inclusion of a well defined transparent queuing procedure is necessary in the FiTs design given the different procurement methods, the small island systems size, and the potential inclusion of caps or target goals on the amount of renewable resources to be procured through FiTs. Queuing establishes a procedure on what project gets interconnected first. DBEDT believes that establishing a queuing procedure requires clear and transparent information on the utilities' interconnection processes at the distribution voltage and at sub-transmission voltage, and this information, except for a copy of Rule 14H, is not available. It is DBEDT's hope that the settlement discussions on the development of the FiT tariffs implementing the Commission's general principles on FiTs design will provide forums for discovery and understanding of the utilities' interconnection processes besides those provided in Rule 14H, and including the process and requirements for the IRS for interconnecting PPAs.

**VIII. If the commission does approve FiTs, what actions can it take to keep total costs reasonable?**

The Commission decision items in this section include whether the Commission should limit the initial FiT scope;

whether to establish purchase caps to keep the total cost reasonable; whether the FiT rates should decline over time, and whether the tariff can state the possibility that the Commission can suspend the FiT based on cost concerns.

DBEDT believes that the eligibility criteria in terms of eligible technologies and project size effectively limit the scope of the initial FiT program. As DBEDT discussed and proposed in Section III above, the initial FiT should be extended to proven, commercially available and RPS-eligible renewable generation resources and technologies which have relatively established operational experience in the HECO Companies' service territories.

The scope of the FiTs program is further limited by limiting the maximum capacity size of projects eligible for FiTs. DBEDT proposed 5 MW for HECO and 3 MW for MECO and HELCO for the initial FiTs as reasonable for reasons discussed Section III above.

If the Commission decides to limit the potential rate impact of FiTs, DBEDT recommends setting target goals in terms of the total quantity of power purchases in megawatts (MW), rather than budget caps in terms of dollars, for the following reasons:

(1) Determining target MW goals rather than dollar caps on total FiTs program costs will more likely allow the more cost-

effective projects to successfully participate in FiTs than capping the total FiTs costs.

(2) Budget caps will require determining what costs to include and how to determine such costs, which adds another layer of complexity and uncertainty to the initial FiTs design.

(3) Budget caps may necessitate or require allocation of such budget caps by resource type and/or by project size, which would also add considerable complexity to the initial FiTs design and could make FiTs too prescriptive and restrictive, which in turn could inhibit the market.

(4) Imposing budget caps to keep the total cost reasonable begs the question as to what total cost is reasonable?

As discussed in DBEDT's FSOP, DBEDT believes that instead of budget caps, the FiTs design should consider including a target total portfolio goal for each resource or technology type based on the determination of the most cost-effective resources allocation to achieve the statutorily mandated renewable portfolio standards (RPS). Upon further consideration, DBEDT also believes that it is reasonable to set a <u>total</u> target MW goal for each island for the initial FiT (rather than setting target goals by resource or technology type) and to let the market forces determine the cost-effective projects to emerge. DBEDT's FSOP also indicated that the HECO Companies' renewable resource commitments in the Energy Agreement may be used as target goals for the feed-in tariff's design. Also upon further consideration, DBEDT believes that there are alternative methods in establishing the total target FiTs goal that may be equally reasonable and merit Commission's consideration. One such method is to base the total program target goal as a percent of the system peak loads in each island system, as was done for NEM. In other words, DBEDT believes that the FiTs program costs are effectively limited by including only select renewable resources and technologies; by limiting the project sizes; and by establishing total target program goals in MW for each island.

With regard to the question of whether or not the tariff can state the possibility that the Commission can suspend the FiT based on cost concerns, DBEDT believes that while the PUC always retains the authority under its statutory grant of power to assure that rates are just and reasonable, it is important to recognize that one major benefit of FiTs is providing clarity, certainty, and stability to the purchased power rates paid by the utilities for purchases of renewable power. As discussed above, the design of FiTs contemplated in this docket, such as applying to selected technologies, limiting the project size, and establishing total target MW goals, already provides limits to the program costs. Additionally, the FiTs process will allow for periodic review, evaluation, and update by the Commission, and the first update has been proposed by some parties to occur two years after the implementation of the initial FiTs. This review and evaluation process will allow the Commission to adjust the program elements, and during such review the PUC could possibly find a compelling need to suspend the FiTs program. DBEDT however believes that future suspension of the program should not and must not affect the projects that are already in service, as well as those that are in the queue. DBEDT believes that including a statement in the tariff of its possible suspension may create uncertainty in the market, and may not achieve the intent of the program. DBEDT instead recommends that the FiT tariffs include a provision relating to the timing and frequency of PUC review and evaluation, and in it include what the review and evaluation could entail. Alternatively, the FiT tariff can simply indicate that the tariff is effective on a certain date and until terminated or suspended by the PUC based on some compelling reasons which will need to be stated in the tariff.

DBEDT also believes that the rate or cost impact of FiTs must be compared with the benefits that will be derived from the implementation of FiTs. The Commission's decision to keep the total cost reasonable should be balanced against the benefits that FiTs will provide in achieving energy independence and security. These benefits include:

(1) The reduction in the barrels of oil used by the HECO Companies resulting from the increased power generation from renewable resources. This is easily quantifiable as the utilities report their fuel consumption in their monthly ECAC filing as well as in their annual FERC Form 1 reports.

(2) The reduction in the barrels of oil used by the HECO Companies resulting from reduction in line losses resulting from the increased in distributed renewable generation enabled by FiTs, as discussed earlier.

(3) The reduction in the HECO Companies' emissions resulting from the reduction in fuel consumption. The emission reductions are easily quantifiable as the utilities report their emissions to the State Department of Health, and US Department of Environmental Protection. The utilities' emissions are also quantified in a report prepared by a consultant for the Greenhouse Gas Task Force pursuant to Act 234, Session Laws of Hawaii 2007. The same methodology used in such report may be used to quantify the utilities' emissions reduction resulting from the implementation of the FiTs program.

(4) The amount of capital investments that flows into the State. This can be quantified through the projects' costs reporting that the FiTs design should require from the project developers.

(5) Estimates of the increase in tax, jobs, and income generated by the inflow of capital investments. This can be quantified by applying the multiplier factors from the State's Input-Output Model.

(6) Estimates of the short run and the long run reductions in the HECO Companies' energy costs (hence in energy rates) by comparing the total fossil fuel costs and the total utility purchased power cost through FiTs.

## DBEDT's DISCUSSION AND POSITION ON THE LEGAL ISSUES

**Introduction and General Approach.** Before addressing the specific legal questions that were put before the Parties in this docket, a few preliminary comments are in order, both to frame the questions presented and clarify their significance in the context of this docket.

*Status of the legal questions.* The concept and wording of the legal questions which are addressed below were the source of vigorous discussion at the panel hearings on April 17, 2009 (the final panel).[43] Unlike the substantive policy issues set forth in the balance of this Brief above, there was no Commission order or other binding procedural pronouncement as to either the

[43] *See* Panel Hearings Transcripts, April 17, 2009, Vol. V, pages 146 - 165, *passim*.

status or the content and wording of these legal questions. Indeed, the Moderator for the panel hearings, an agent of the Commission during the hearing, stated in the record with respect to these legal issues that

> [W]hat I propose to do... is simply have an informal discussion about whether these are the legal issues, or is there anything left out, is there anything unclear about the way we stated the legal issues, and then they can all be briefed. Because there are a certain number of statutory interpretation questions, procedural questions, that come up in various ways. ... just prepare to ensure the Commission understands what all the legal questions are.[44] [emphasis added]

Later in the hearings, the Moderator reiterated:

> These are unofficial legal questions. These are legal questions that I and counsel developed by listening over the last week and also by reading your legal submissions earlier in the case and asking ourselves what legal issues remain unanswered.... This list doesn't represent a mandate at all. Ultimately, the Commission will decide whether to specify what legal questions should be discussed in your briefs, but our conversation tomorrow will help the Commission do that.... eventually, the Commission may make that document or some variant of it official; meaning, these are the questions the Commission wants you to address in your brief.[45] [emphasis added]

Although the Commission's counsel did in fact collect, edit, and send all Parties a summary of the legal questions generated and discussed during that final session at the panel hearings, there was no official act serving as an indication that the Commission stamped its imprimatur on these questions,

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[44] Panel Hearings Transcripts, April 13, 2009, Vol. I, page 25.
[45] Panel Hearings Transcripts, April 16, 2009, Vol. IV, page 286.

either in form or substance. Since DBEDT believes that the Commission is interested in the answers to these questions, and further believes that there are in fact important issues raised therein, we will proceed to address each such question in the exact form that it was distributed for review to the Parties by electronic mail from Commission counsel on May 7, 2009, wherein counsel stated that the attached list constituted a "recap of the legal questions that were identified at the hearing for post hearing briefing."

*The significance of PURPA and its interplay with section 269-27.2, HRS.* The existence of federal law mandating that "just and reasonable" rates to customers of utilities that have been compelled to purchase electric energy from qualifying small power production facilities are rates which, *inter alia*, do not exceed the "incremental cost to the electric utility of alternative electric energy"[46] (the so-called "avoided cost" -- that is -- "the cost to the electric utility of the electric energy which, but for the purchase from such... small power producer, such utility would generate or purchase from another source"[47]) has cast some doubt over the propriety of this entire proceeding, inasmuch as an unconditional, non-contextual application of this rule could be interpreted as prohibiting the

[46] 16 U.S.C. § 824a-3(b), within those sections of the Federal Power Act generally referred to as "PURPA".
[47] 16 U.S.C. § 824a-3(d)

Commission from ordering any FiT that could eventuate in a cost to the ratepayer higher than the relevant avoided cost.

There are courts that have examined this issue and held that PURPA does *not* preempt state laws which require "electric utilities to offer to buy energy from... alternate energy producers... at a rate in excess of the maximum rate under PURPA." In the Matter of Consolidate Edison Co. of New York v. Public Service Commission of the State of New York, 63 N.Y.2d 424, 430; 472 N.E.2d 981, 982 (1984); appeal dismissed 470 U.S. 1075, 105 S.Ct. 1831 (1985). In fact, the United States Supreme Court, in a dissent[48] by Justice White, noted that

> FERC, in explaining its regulations, had said that "the States are free under their own authority, to enact laws or regulations providing for rates which would result in even greater encouragement of these technologies," and that only state rates *below* the federal rate would have to "yield to federal law." 45 Fed.Reg., at 12221 [470 U.S. 1075 at 1077]

The law in this area continued to develop since that time, however, including several pronouncements from the Federal Energy Regulatory Commission (FERC) that made it clear that in cases in which it retained jurisdiction, state utility commissions could not compel rates above the utility's avoided cost. In its order in FERC Docket No. EL93-55-000, reported at

[48] The dissent ironically was only on the issue of whether the question of FERC preemption of state law posed "a substantial federal question" or not. The majority held that it did not pose a substantial question, which when read in the context of the lower court's opinion implies that the Court believed there was no federal preemption of state law.

70 FERC P 61012, 1995 WL 9931 (F.E.R.C.), the FERC makes clear its understanding of the regulatory framework around the preemption question which, although applied only to Connecticut Light and Power Company in its order, is repeated below for its broader application:

> Whether the rate prescribed by [state] statute is preempted depends on the type of facility involved [qualifying facility (QF) or non-QF] and the identity of the seller of power from the facility (public utility or non-public utility). There are three general scenarios that may fall within the reach of the [state] statute, and each presents different jurisdictional implications. First, if the facility addressed by the [state] statute is a qualifying facility (QF) under PURPA, this Commission has responsibility for the QF's rates for sales for resale. Rates may be established by the state but only pursuant to and consistent with this Commission's regulations under PURPA. Second, if the facility addressed by the [state] statute is not a QF but the seller is a public utility within the meaning of the Federal Power Act (FPA), this Commission has exclusive jurisdiction over its rates for sales for resale in interstate commerce. States may not set rates for public utility sales for resale in interstate commerce. Finally, if the facility addressed by the [state] statute is not a QF and the seller is not a public utility, but, for example, instead is a governmental entity within the scope of section 201(f) of FPA, this Commission does not have jurisdiction over its rates.

Under this analysis, it appears clear that FERC believes renewable energy producers that explicitly seek qualifying facility (QF) status under PURPA will trigger federal PURPA jurisdiction (including the avoided cost ceiling). As suggested by counsel for Blue Planet in its Response to Questions 1-3 of Appendix C (to the NRRI Scoping Paper on FiTs) filed with the

Commission on January 12, 2009, a Hawaii FiT "may be available only to renewable electricity producers who do not seek [ ] status as a QF under PURPA." Blue Planet Response at 10.

Even if QF status is avoided, the FERC ruling goes on to assert primary jurisdiction over non-QFs who are deemed "public utilities" under the Federal Power Act (FPA) and sell for resale in interstate commerce. The definition of "public utility" under the FPA is unfortunately circuitous: "any person who owns or operates facilities subject to the jurisdiction of the Commission [i.e. FERC] under this subchapter";[49] however, it is worth mentioning from a policy aspect that wholesale renewable power producers are explicitly excepted from the definition of "public utility" under Hawaii law.[50] More decisively however, no sales from any renewable energy producer in this State would at this time be a sale made "in interstate commerce"[51] and therefore FERC's exclusive jurisdiction is lost under the second jurisdictional prong cited above.

Finally, FERC allows that if the producer is neither a QF nor a "public utility", the FERC has no jurisdiction over its rates. Therefore, given the above analysis, it appears that

[49] 16 U.S.C. §824(e)

[50] Section 269-1, definition if "public utility" at (2)(G)(i), (ii).

[51] Although the FERC rejected the Hawaii Consumer Advocate's arguments asserting lack of FERC jurisdiction for determining QF status for Kalaeloa Partners, L.P. in 1989 (48 FERC ¶ 61,173), the FERC in the same Order specifically stated that "[Hawaii] has no sales for resale or transmission in interstate commerce." 48 FERC ¶ 61,173 at 5.

even under the FERC's own standards (which have been uniformly aggressive over the years), if a renewable energy producer under a Hawaii FiT does not seek registration as a QF with the FERC and does not effect sales in interstate commerce, the Hawaii Public Utilities Commission has primary and indeed unique jurisdiction over those rates, as a matter of both federal and state law.[52]

*Recent legislative and gubernatorial actions.* Now that it appears that Hawaii state law is decisive on the matter of rates for renewable energy producers selling to the utility under a FiT, it becomes important to consider recent changes in that state law.

Hawaii's "state PURPA law" is found at section 269-27.2, HRS.[53] In its most recent legislative session, the Hawaii legislature passed House Bill No. 1270, House Draft 1, Senate Draft 2, which was signed into law by the Governor on May 6, 2009, as Act 50, Session Laws of Hawaii (SLH) 2009. Act 50, SLH 2009, removes the statutory limitation on the PUC that the "just

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[52] It may also be reasonably argued that a FiT is transactionally a standardized, open "offer to purchase", and so any renewable producer under a FiT arrangement, having "accepted the utility offer" when it sells under the FiT, proceeds under the already extant and permissive language of section 269-27.2(c), as availing itself of a rate that "shall be as agreed between the public utility and the supplier and as approved by the public utilities commission." This falls outside the scope of even the previous state "avoided cost" cap language *and* the federal law's application only to "compelled purchases". Public Util. Comm'n of Texas v. Gulf States Utilities Co., 809 S.W.2d 201, 208 (Tex. 1991)

[53] Rules implementing this State PURPA law are set forth at Title 6, Chapter 74, Hawaii Administrative Rules.

and reasonable rates" it determines for electricity purchased by a utility from nonfossil fuel generators cannot be set at a rate higher than "avoided cost". Act 50 simply deletes the "avoided cost" language limitation set forth in subsection 269-27.2(c), HRS. Further, Act 50 adds an alternative "just and reasonable" standard to the definition of "cost-effective" in section 269-91, HRS (in the renewable portfolio standards part of chapter 269). This addition allows the PUC to sanction nonfossil fuel generation that would otherwise not be available to the utility for meeting its RPS goals when the cost of the nonfossil generation is above the utility's avoided cost. This definitional change conforms the renewable portfolio standards review process to the intent of the amendment to section 269-27.2(c), HRS, and also denies the utility the otherwise available defense that it could not meet its portfolio requirements because the renewable generation available to it is not "cost-effective" and therefore need not (or even cannot) be purchased.

Hence, in Hawaii, a FiT, duly-approved by the Commission and applied to domestic renewable energy producers, may issue for generation at a rate which may be above the purchasing utility's avoided cost.

With those preliminary issues now set forth and understood, we proceed to the legal questions sent to the Parties by Commission counsel, which were summarized in a form intended to be representative of the material legal issues that arose during the panel hearings.[54]

## IX. General

> A. Does Section 269-27.2(b), HRS, empower the Commission to establish a set of feed-in tariffs that compel the utility to offer to purchase power from nonfossil producers at rates, terms and conditions established by the Commission, even if those rates, terms and conditions differ from those proposed by the utility in this proceeding?

Subsection 269-27.2(b), HRS, does nothing to disallow the PUC from establishing FiTs rates which compel the purchase of renewable energy at rates different from those proposed by HECO in this docket. This subsection of state law simply authorizes the Commission to "direct public utilities... to arrange for the acquisition of and to acquire electricity generated from nonfossil fuel sources...."; it says nothing about what form that direction may take. It is subsection 269-27.2(c), HRS, as amended by Act 50 mentioned above, that gives the Commission the

[54] Please note that the legal issue section has been renumbered from the scheme proposed by Commission counsel. Since DBEDT has responded to the main panel hearing issues in the main part of this Opening Brief (I-VIII) following the order and categories set forth in the transcripts and the Commission's Order Establishing Hearing Procedures dated April 1, 2009, we begin the legal issues at section IX (IX - XII) rather than section VI (VI - IX) as Commission counsel has done.

authority to proceed with this investigatory docket, and then ultimately establish FiTs rates, under the "powers and procedures provided in this chapter" provision. This subsection grants the Commission the authority to establish just and reasonable rates, and now without the limitation of setting those rates with reference to avoided cost.

> B. Does the Commission have authority to mandate that the utility procure a particular quantity of nonfossil electricity, exceeding the statutory RPS requirements? Can the Commission establish deadlines? What statutes grant this authority?

The Commission does indeed have the authority to mandate quantities of renewable generation above the RPS requirements. Section 269-94, HRS, states in part that "[t]he public utilities commission may provide incentives to encourage electric utility companies to exceed their renewable portfolio standards...". Hence, the Commission is authorized to mandate amounts above existing RPS levels. Further, the Commission can establish deadlines under subsection 269-27.2(c), as amended by Act 50, by availing itself of its powers in rate setting under section 269-16, HRS. Statutory authority to set deadlines also comes from section 269-27.2(b), HRS, wherein it is stated that the Commission "may develop reasonable guidelines and timetables for the creation and implementation of power purchase agreements."

C. Is the Energy Agreement legally binding on any one? In what way? Who could sue whom for noncompliance?

Whatever the legal status of the Energy Agreement entered into between the State and the HECO Companies on October 20, 2008 may be, it is at the least an agreement, signed by the parties to be charged, setting forth language of commitment, including explicit covenants to work together in good faith. Within it, HECO commits to strive to do certain things, in consideration for which the State shall use its best efforts to help. Acknowledging then within the text of the Energy Agreement that there are words establishing covenants, in writing, for which affirmative acts or forbearance from certain acts is expressed as consideration therefor, such signed memorializations are generally at law accorded the status of a contract enforceable among the charged parties. Under this analysis, the parties thereto could sue one another for non-performance of the explicit covenant of good faith without invoking either equitable doctrines or implied covenants in quasi-contract. Since agreements can also be made binding and enforceable under the common law through reasonable reliance of the aggrieved party, or by equitable estoppel, for instance, it appears clear that the Energy Agreement is binding among the parties that signed it, at least to the extent that any detrimental change in position of a party due to its reasonable reliance on extrinsic or implied promises in the Agreement could be the subject matter of a legal claim.

It is quite clear that the Commission is neither directly nor by implication bound to any of the terms of the Energy Agreement. It is not a party to the Agreement, and its statutorily conferred regulatory and quasi-judicial powers are inconsistent with its having any obligations under the Agreement. DBEDT does note in passing however that the Energy Agreement is evidently at least more than a nullity in the Commission's eyes, inasmuch as it opened the instant docket referencing the Agreement. That act of course does not create any legal obligation on the part of the Commission.

D. Does the Commission have authority to adopt FiTs in this proceeding without having completed a proceeding on Clean Energy Scenario Planning?

There is no question that the timing of other, inter-related dockets cannot erode the principal authority the Commission enjoys to adopt FiTs after due investigation and deliberation (*see* section IX.B. above for those grants of authority). Whether the Commission may or may not deem it prudent to adopt a feed-in tariff before it has had the opportunity to explore some of the issues inter-related to the general state energy goals is a matter of Commission discretion, and not a legal issue. DBEDT would point out however that there are several dockets open currently (wheeling, FiTs, decoupling, PV Host, and CESP), each of which has shared issues and possible inter-related effects. If the Commission were to construe its statutory obligations to be consistent with proceeding no further in any docket until related material issues are resolved, arguably all these dockets would be at a standstill. DBEDT's suggestions earlier in this Brief to have a more flexible FiTs framework with review of the process over time can accommodate some of the concerns of this nature.

> E. Under a FiT regime, will there still be a need for a contract between seller and the utility buyer? What form would these written contracts take? What seller obligations should these contracts cover?

Under a FiT regime, there will still be a need for a contract between the renewable energy producer and the purchasing utility to the extent that there will remain specific terms peculiar to specific producers that need to be addressed. Any variable of seller's obligations to perform that might be relevant and are allowed, but not stipulated, by the FiTs, could be set forth in an ancillary agreement, with the FiT (tariff sheet) attached. Such a contract could also be useful when there are any particular agreements (for interconnection, for instance) that vary from the FiT standard but are helpful to the seller and acceptable to the utility. Rather than accepting the standard FiT, the parties could set forth their agreement in such a contract.

> F. Assuming there are contracts associated with FiT sales, what is the Commission's statutory obligation to review these contracts? What are effective procedures to expedite Commission review?

The Commission's *statutory* obligations to review these FiTs-related contracts will of course depend upon what sort of contract is entered into and what the specifics of the contract are. Looking to the Commission's existing mandate under section 269-27.2, HRS, and the administrative rules promulgated thereunder (§ 6-74-1 *et seq.*) for guidance, any given FiTs contract would have to be reviewed by the Commission to make sure that there are no provisions in it at variance with section 269-27.2, as amended. If such review becomes too difficult to expedite for any reason, there could be a provision to automatically effectuate the contract in 90 days unless subsequently suspended by the Commission. Since it is unlikely that the Parties to this docket would ever agree to a comprehensive list of review and adoption rights and obligations, the feed-in tariff instrument itself is not the place to set forth those rights and obligations.

## X. Cost

A. Does HRS § 269-27.2 impose any limit on total cost? For example:

1. Does the phrase "maximize the reduction in fossil fuels" in Section 269-27.2(b) <u>allow</u> the Commission to establish a quantity goal, determine the rate necessary to satisfy that goal, and impose that rate regardless of how high the rate is and regardless of total cost?

Section 269-27.2, HRS, as amended by Act 50, SLH 2009, does not impose any limit on total cost *per se*.

The phrase "maximize the reduction in fossil fuels" in section 269-27.2(b) *allows* the PUC both to establish a goal and determine a rate necessary for that goal, but it does not *mandate* imposing that rate regardless of how high the rate or total cost is; the "just and reasonable" parameter set forth in section 269-16, HRS and throughout the chapter serves as a check on untempered maximization. Further, the "reasonable guideline" language of subsection 269-27.2(b), HRS cited above, and the tension between subsections 269-27.2(d)(3),(4) HRS (promoting energy self-sufficiency and non-fossil policies) on the one hand versus subsections 269-27.2(d)(1),(2) HRS (assurance of just and reasonable rates, fairness to ratepayers policy) on the other to implement the "overall best interest of the general public" (section 269-27.2(d)(5)) comprises the effective balancing test with which the Commission has always been charged under chapter 269.

2. Does the "maximize" phrase <u>mandate</u> that result?

"Mandate" can simply mean "authorize", not "prescribe" or "proscribe". The Commission's authority has always been bounded by settled equitable principles and looking out for the overall best interest of the general public. The Commission is *authorized* to satisfy these goals in the best all-around way, after considering all the results, but is not *forced* to adopt one type of rate setting. And as the next question suggests, whatever this mandate may entail, it is introduced by the word "may", not "shall". It is against the very nature of regulation to lock in outcomes that may lead to a reversal of the very policies that led to the institution of the regulatory scheme in the first place. Some flexibility must be and is always built in to the process.

> 3. If you believe the "maximize" phrase mandates that result, what effect does the discretionary term "may" have on the Commission's obligation?

Not applicable; *see* X.A.2. above.

> 4. Can the Commission determine a required quantity for the utility to purchase, and then set the rate at whatever level is necessary to attract that quantity? Would such a rate necessarily satisfy the just and reasonable standard?

If the Commission were to first determine a target quantity of renewable energy for utility purchase and then set the FiT rate to reach that result, it could betray the basic tenet of "just and reasonable" rates by promoting an outcome which may not be in the best interests of the general public. Such an approach is also not in line with the explicit statutory scheme of chapter 269. No rate can by its nature "necessarily satisfy" a just and reasonable standard, because it must be context-sensitive and fact-specific. The concept of "required quantity" is more like the approach adopted in the RPS law, but no rates are tied to those quantities explicitly. The mandate in the law is for the Commission to move toward more renewable energy, as quickly as is consistent with the total public good.

> B. Regardless of any statutory limit on cost, does the Commission have authority to establish a dollar limit on the cost of utility acquisition of nonfossil electricity pursuant to an FIT? What statutes grant this authority?

Noting first that the most obvious statutory limit on cost, "avoided cost", has been read out of section 269-27.2 by Act 50, SLH 2009, the Commission does nevertheless retain authority to establish a dollar limit on the cost of utility acquisition of renewable energy pursuant to a FiT. The "just and reasonable" standard will again assert itself as the Commission's general guide and authority to limit costs to the utility for the public benefit. *See*, for example, sections 269-16 and 269-27.2(d), HRS. The difficulty in exercising this authority is that tere are both tangible, monetized costs and intangible, longer-term costs avoided that need to be balanced.

Another concern related to the Commission's authority to establish dollar caps on utility acquisition of renewable energy under a FiT, and raised by the Commission in its Order Establishing Hearing Procedures, is whether the FiT should or could state that the PUC can suspend the FiT based on cost concerns. While it is clear that the PUC always retains the authority under its statutory grant of power to assure that rates are just and reasonable, it cannot (or at least it is argued here *should* not) suspend an ongoing FiT without having specific, clear, non-arbitrary and objectively provable triggers set forth in the tariff from the outset. Clear, objective, well-motivated standards for suspension, articulated "up front" by the Commission, will allow parties to the tariff to conduct themselves in the best interests of their own enterprise and assure a certain level of economic stability necessary for supporting the drive for more renewable energy which is at the heart of the FiT program. Anything less could have disastrous effects on the renewable industry and discourage investment in the distributed production of renewable energy. The regulatory sword of suspension hanging over a Commission approved FiT could also obscure or create issues under the "filed rate doctrine" and vitiate the predictability that is the hallmark of prudently applied regulatory oversight.

> C. Does this authority to establish a dollar limit apply only to acquisition above the quantities required by the RPS statute?

By adding an alternative "just and reasonable" standard to the definition of "cost-effective" in section 269-91 (in the RPS section of chapter 269), Act 50, SLH 2009 allows the Commission to sanction nonfossil fuel generation that would otherwise not be available to the utility for meeting its renewable energy standards goals when the cost of the nonfossil generation is above the utility's avoided cost. This definitional change conforms the renewable portfolio standards review process to the intent of the amendment to section 269-27.2(c), HRS, and also denies the utility the otherwise available defense that it could not meet its portfolio requirements because the only renewable generation available to it is not "cost-effective" and therefore need not be purchased. As amended, amounts both above and below the RPS level are subject only to the general just and reasonable standard, shorn of "avoided cost" considerations.

## XI. Sellers' Legal Rights

### A. PURPA

> 1. Does a nonfossil developer have an existing statutory right, under state law or PURPA, to a

> negotiated PPA? If so, does that right continue even if the Commission establishes FiTs that constitute utility offers to buy at a stated rate, or can the Commission make the FiT the exclusive means by which nonfossil producers sell to the utility? Put another way, if there is a FiT applicable to a particular seller, may the Commission authorize (or forbid) the utility to negotiate a PPA on terms that vary from the FiT?

Nonfossil producers at present have an existing right under state law to a negotiated PPA. If the renewable energy producer can negotiate with the utility and reach a mutual agreement, that right is codified at section 269-27.2(c), HRS, before the proviso language of that subsection. If the renewable energy producer cannot reach an agreement with the utility, of course, the Commission enters the stage. Whether a right to a negotiated PPA would survive the institution of a FiT would be a policy decision, not a statutory/legal decision. There is no legal reason why the two regimes could not exist side by side, but there may be policy reasons why both the renewable energy producer and the utility would prefer the FiT to replace negotiation. The Commission could authorize or forbid the utility to negotiate a PPA on terms that vary from the FiT if the FiT is available to the renewable energy producer. When instituting the FiT, the Commission should make a finding that it is just and reasonable and that the system satisfies the statutory requirements and balancing of subsections 269-27.2(d)(1)-(5).

> 2. Can the Commission substitute a FiT for Schedule Q, as a means of complying with PURPA? What type of issuance from the Commission would be necessary to demonstrate PURPA compliance?

The Commission can substitute a FiT for Schedule Q; *see* section XI.A.1. above. Existing Schedule Q QFs may need grandfathering or other relief (as a matter of regulatory law or common law contract), but "compliance with PURPA" is not an issue under FiTs; it is simply a new way under state law to comply with the PURPA policies.

> B. Does HRS § 269-27.2 create any legal rights in sellers of nonfossil power? For example:
>
> 1. Does the phrase "just and reasonable rate" in HRS § 269-27.2(c) mean "just and reasonable" to the seller, or only "just and reasonable" to the consumer? That is, does the phrase "just and reasonable rate" allow a seller to contest a Commission-established FiT on the grounds that the rate is too low or that non-rate terms and conditions are unfavorable?

To be fair, the "just and reasonable" language in subsection 269-27.2(c), HRS, is most likely with reference to the consumer of renewable energy, not the seller, since section 269-27.2(d)(1) refers to "the amount recovered by the utility and the amount of increase in rates due to the payments for firm capacity and related revenue taxes to be charged to the *consumers* of the electricity" being found "just and reasonable". Further, the PURPA language on which this section of the statute was based (16 USC § 824a-3(b)(1)) refers to the rates being "just and reasonable to the electric consumers of the electric utility and in the public interest".

However, this question appears to be considering the concept of a rate case-like proceeding attacking an established FiTs rate. Such a proceeding would go against the point and policy underlying the establishment of a FiTs. Arguments and documentation supporting a given rate or rates need to be put before the Commission *before* the FiTs is published; the rate agreed upon in the tariff needs to stay in place until the next scheduled revision. If any FiT could be attacked on a case by case basis, the purpose behind standardized contract offers would be lost.

> 2. On what specific grounds could the seller contest the rate? That the rate produces a return on equity too low to attract sellers? How would the seller prove this case, to the Commission and to reviewing courts? What data would the Commission have to rely on to insulate its rate decision from judicial reversal? What evidentiary burden does the seller have, to supply facts to the Commission so that the Commission has the necessary factual support for its decision?

*See* response to section XI.B.1. above.

> 3. If the Commission declined to establish any FiT rates, but instead authorized the utility to self-produce or purchase renewables as the utility deems appropriate, would the sellers have any legal claim against the utility or the Commission? If the answer is no, then do the sellers have any legal right to contest a Commission-established FiT?

Sellers would have no legal claim against the utility or the Commission if the Commission declined to establish FiT rates, because there is no underlying right to a feed-in tariff under chapter 269, HRS, merely guiding principles and a mandate to use less fossil fuel in the generation of electricity. This lack of an express right to a FiT would not however eventuate in the utility being able to "do as it deems appropriate", since the utility is still subject to PUC regulation and has to justify its actions accordingly.

There is no precise legal connection between a seller having a right (or not) to contest the absence of a FiT regime and sellers having a right to contest a FiT that has been established; the lack of one (which is admitted) does not imply the other. However, as mentioned above in section XI.B.1., if any FiT could be challenged on a case by case basis, the purpose behind standardized contract offers would be lost.

C. Assuming the Commission establishes FITs, may the Commission authorize (or forbid) sellers with existing PPAs to terminate the PPA and enter into an agreement under the FIT? Under what conditions? With what Commission involvement?

A PPA, once approved by the Commission, is a binding contract between the parties, and ordinarily could not be terminated except in accordance with its terms, including the consent of both parties. Existing PPAs could be transitioned to a FiT under Commission scrutiny if both the utility and the renewable energy producer agree, and assuming the renewable energy producer is producing under a FiTs eligible technology. There are many possible reasons why a unilateral termination of a PPA would not receive PUC approval; any transition to FiTs would have to be approved through at least an abbreviated docket procedure.

D. Hawaii statutes prohibit undue discrimination in the provision of utility service. How does that prohibition apply in the context of FiTs? For example:

1. Can there be different rates for different technologies/sizes/islands: What factual differences are necessary to justify rate differences?

The anti-discrimination provisions of chapter 269, at for instance section 269-16(b)(2)(B), prohibit unreasonable discrimination between consumers under substantially similar conditions. The differences noted in the question above constitute *reasonable* discrimination because the power produced and its effect on the grid would be substantially dissimilar according to technology, size, and island. Therefore there can and should be different rates under these three categories.

2. Can there be negotiated PPAs that make use of FiT rates but that vary from each other in other terms and conditions?

There is no categorical or legal reason why a FiT rate could not be used as a market referent in a negotiated PPA, but there should be some other reason why the renewable energy producer in question could not avail itself of the FiT rate; if it is eligible for FiTs, it should use FiTs.

3. Can there be a negotiated PPA for projects that qualify under the scope of an existing FIT?

There should not be; *see* XI.D.2. above.

## XII. Utility Role

A. Does the Commission have the power to restrict the utility's ability to build its own nonfossil generation, such as requiring the utility to refrain from building whenever there is a viable independent seller offering to sell? What findings must the Commission make to support such a restriction?

There is no single, valid legal answer to this question: it is in part a policy matter. Motivation and the drive for more distributed generation and a viable renewable contractor market may be stifled by what could appear to be the "unfair" leverage of the utility getting a "right of first refusal" on every renewable business opportunity, or using its position to ensure or help get the edge on contracting for renewable energy projects, but the Commission would have to open an investigatory docket and make specific findings that this use of the utility's market power somehow defeats one or more of the important policy goals of chapter 269: to the extent a renewable energy producer must be chosen over the utility for an otherwise equivalent renewable project, some policy beyond accelerating the use of more renewable energy in the State must be balanced against the efficiencies of relying on the perhaps more readily deployed assets of the incumbent utility.

> B. Same question as above, but applied to a utility affiliate selling renewable energy to another utility affiliate.

This is essentially the same question as XII.A., inasmuch as an inter-affiliate transaction would displace otherwise ready/willing/able renewable generation. With no express prohibition within chapter 269, the Commission would have to come up with a value-goal calculus that justified such a prohibition.

## CONCLUSION

In summary, the Hawaii Public Utilities Commission has authority under state law to approve a feed-in tariff program unconstrained by the avoided cost cap repealed under Act 50, SLH 2009. Such a program is desirable for Hawaii as both the State and the utility companies move together to accomplish the goals of the Energy Agreement and the FiT: to accomplish the HCEI and State energy goals to move decisively and irreversibly away from imported fossil fuel for Hawaii's energy source and towards indigenously produced renewable energy; to stimulate the rapid development of renewable energy in Hawaii; and to accelerate the pace of acquisition of renewable energy by the HECO Companies in order to reduce Hawaii's dependence on imported fossil fuel.

The initial feed-in tariffs should be extended to all proven, commercially available and RPS-eligible renewable generation resources and technologies which have relatively established operational experience in the HECO Companies' service territories, including wind, solar (PV and CSP), hydro, biomass, biogas, and geothermal. The initial FiT should replace future utility procurement under non-bid purchase power contracting for FiTs-eligible renewable projects with capacity size of 5 MW or less for Oahu, and 3 MW or less for HELCO and MECO. To the extent that Hawaii-specific cost data is not available for most project size and technology combination and by island, secondary data sources for industry costs may fill the information gap for setting the initial FiT rates. The data from secondary sources should be reasonably adjusted to reflect the Hawaii market, but we should not delay the FiT program until a body of well-developed Hawaii data is available.

DBEDT also recommends setting target goals for each island system in terms of the total quantity of power purchases in megawatts (MW), rather than budget caps in terms of dollars. We also believe that there are alternative methods of establishing these target MW goals, such as using HECO's commitments in the Energy Agreement, or establishing the MW targets based on some percent of the system peak load in each island system as done in NEM. DBEDT also believes that just and reasonable FiTs require clear, efficient, transparent, and streamlined interconnection rules, standards, and procedures for interconnecting the renewable power generating facility designed to sell power to the utility system.

Finally, DBEDT believes that the Commission is empowered at this critical juncture in Hawaii's energy history to implement a feed-in tariff system which, once established and fine-tuned over time and experience, will represent an important step down the road to this state's energy sustainable, secure, and environmentally safe future.

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## Certificate of Service

I hereby certify that I have served a copy of the Department of Business, Economic Development, and Tourism's Opening Briefs in PUC Docket Number 2008-0273, by electronic transmission on the date of signature to each of the parties listed below.

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